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TECHNICAL AND ECONOMIC POTENTIALS
OF SHALE OIL PRODUCTION BY
NUCLEAR EXPLOSIVES

by

Klaus-Peter Heiss

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PNE-3006
NUCLEAR EXPLOSIONS - PEACEFUL
APPLICATIONS (TID - 4500)

TECHNICAL AND ECONOMIC POTENTIALS OF
SHALE OIL PRODUCTION BY NUCLEAR EXPLOSIVES

by

Klaus-Peter Heiss

SPECIAL REPORT

prepared for

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MATHEMATICA
Princeton, New Jersey

August 31, 1967

Since the Plowshare Program was established in 1957 to investigate and develop peaceful uses for nuclear explosives, a large number and variety of applications have been suggested. As a result of the Plowshare research effort, many suggestions have been discarded for technical reasons while others have been more clearly identified as long-range possibilities requiring still more data and further development. Other ideas have now been sufficiently developed and offer enough promise to warrant the type of pilot-scale or prototype experiment needed to obtain precise information in an industrial framework.

By the time such an experiment is seriously considered and proposed, there is a need for some general economic appraisal of the potential value of the application. In the course of research some economic information is usually generated; however, for the most part, the AEC has relied primarily on government agencies responsible for resource development and on industry for information and general economic evaluations. As a result, this information and analysis is scattered throughout different reports, and appraisals have often been made on different bases and with different assumptions and resource information. Since a number of these applications are now approaching a commercial technology level, it seems timely and desirable to make some effort to collect this information, put it on as consistent a basis as possible, place it in the proper economic and resource perspective, and include enough relevant technical and cost information about nuclear explosions, their effects and associated operations, to permit a better and more detailed analysis from an economic point of view.

To these ends, Mathematica Incorporated of Princeton, New Jersey, was engaged to carry out this assignment. They have produced a series of reports covering the various areas of application for peaceful nuclear explosions and a general summary report. These reports are not intended to be definitive economic analyses, since sufficient data is still not available for such analysis. Rather, these studies are intended to serve as a beginning point and a means of identifying on a consistent basis the range of potential of the presently known, most promising applications. It is hoped that they will serve as a useful guide for future economic studies, especially by identifying key technical questions which affect the economics of the applications, such as whether the fractured area of oil shale surrounding the nuclear chimney can also be retorted. It is towards answering these key technical questions that much research and development, including the design of current experiments, is being devoted. Beyond the identification of key technical questions, these studies attempt to define the controlling economic parameters for the different applications, such as the diameter of explosives and concomitantly the cost of very deep drill holes for the gas production stimulation applications.

With the expectation that this information will be of general interest, as well as a guide for the research of those working in Plowshare, the AEC is pleased to make these reports available.

John S. Kelly, Director
Division of Peaceful
Nuclear Explosives

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INTRODUCTION AND SUMMARY

The largest single reserve of hydrocarbons known to exist anywhere in the world is given by the oil shales of the Green River formation in the western part of the United States. With available conventional techniques only an insignificant part of these resources could be tapped, and that only at great cost and under considerable technical uncertainties. It is on this basis that the Oil Shale Advisory Board came in 1964 to the negative conclusion that such an oil shale industry would not be competitive under conditions as they were at that time.

In the following report a new technology is discussed which was first proposed in 1959, but which has been developed mainly since 1964: the in situ production of oil from shale by large underground retorts created by nuclear explosives. The first part of the present report describes this new process; the second part gives an analysis of the United States and the world endowments with crude oil resources and oil shale deposits and finally, the third part deals with expected cost estimates of this new technology as compared with present crude oil prices and potential costs of conventional shale oil production. The main findings are:

1. Crude oil resources, both of the United States and the world, are limited, and if related to present production levels, serious scarcities

will develop within the next generation (35 years). This conclusion takes account of substantial additions to crude oil resources during this period.

2. The main organic matter reserves of the United States and the world are in the form of coal deposits and oil shales. Oil shale deposits may equal expected coal deposits in energy content. At least in the long run these two resources will be the main base of fossil fuels and organic material production. The known, measured oil shale and reasonably inferred resources in Colorado alone exceed "known and measured" United States crude oil resources by a factor of 100 and total maximum expected recovery of crude oil resources by a factor of 10.

3. The expected technical parameters in nuclear in situ retorting of oil shale would allow a shale oil production at substantially lower costs than present crude oil production. This is mainly due to:

- a. the elimination of finding costs, as the shale deposits discussed here are known and measured. The only open question is their ultimate extent, not their location. There may, of course, exist additional oil shale deposits not yet discovered.
- b. increasing economies of scale in the thick oil shale formations of the Green River area for nuclear in situ methods.
- c. substantial external economies due to a reduction in labor requirements and water requirements and a near exclusion of waste disposal problems by the nuclear in situ retorting process.

d. the present crude oil industry enjoys a 27.5 per cent depletion allowance which is reflected in the extent of their operations and in part in crude oil prices. In the present analysis no such allowance was made for shale oil production costs, though potentially shale oil production by any in situ production method might be entitled to an identical allowance.

4. The nuclear in situ retorting method would enable the U. S. economy to expand petroleum production at will without substantial cost increase.

5. The extension of petroleum supplies for the U. S. by this new technology would be in excess of 100 years allowing even for a 3 per cent annual expansion of total petroleum demand. This compares with the time horizon of proven crude oil reserves of ten years only. Potentially, this expansion could extend to 200 or more years within the U. S.

6. The nuclear in situ method would not discriminate against private industry or any firm that wants to participate in such an undertaking and is able to do so financially.

Against these expectations stands mainly the fact that no nuclear in situ retorting experiment has yet been conducted. Such experiments could lead to substantial changes in expected costs in both directions, cost-savings and cost-increases. In particular, this study found that variations in the technical parameters could be such that the nuclear in situ process

would still be economically feasible down to a recovery rate of 30 per cent of the shale oil present. Similarly, if present parameters are confirmed, the nuclear in situ process could be extended by various processes economically to recover shale oil from very low-grade deposits (five gallon per ton grade instead of 25 gallon per ton grade oil shales) extending thereby substantially the exploitable oil shale reserves.

Uncertainties as to compressor requirements were found to be the most serious variable in expected shale oil production costs.

The nuclear in situ technique would be mainly applied in formations exceeding 100 feet in thickness. This is due to the discrete size of any nuclear explosion and the fixed costs incurred independently of the yield of the explosive. Thus, the nuclear in situ technique does not directly compete with most conventional mining-retorting techniques developed by some firms at present.

If the nuclear in situ technique proves to be successful and confirms expectations anywhere in the neighborhood of present figures, a substantial shale oil industry could develop within the U. S. and ultimately replace crude oil production at an annual rate of 10 to 15 billion dollars per year of gross output. In addition, this technique would constitute one of the first forms of production in which the fusion energy would be utilized with advantage for peaceful purposes.

These considerations alone would justify a substantial research and development program of the peaceful application of nuclear explosives far in excess of present efforts. Whether these parameters are realistic will have to be tested by experiments.

Chapter 1

PHENOMENOLOGY

1.1 HISTORICAL REMARKS

It is possible that some form of shale oil was the first form of fossil oil known. The word "petroleum" can be traced to oil shales: The word is composed of "petra" (rock) and "oleum" (oil). Most likely it was first discovered by accident when oil shale rocks were used in building a fireplace, as at normal temperatures oil shale is "dry" and relatively hard. [86, pp. 1 ff.].

As to the origin of oil shale formations, no controversy exists. Dating back to Carbonian and Tertiary sediment formations, oil shales were formed by the deposition of fine organic matter in or near the center of lakes, where it intermingled with inorganic compounds. The organic matter was transformed to kerogen. The extensive Green River formation (Colorado, Utah, Wyoming) in particular originated from two huge lakes, Lake Uinta and Lake Gosiute [113] (see Figure 1.1 below) [91]. Similar conditions must also have held in many other places on various continents, at least in similar climatic regions. This would indicate a wide dispersion of world oil shale resources. Oil shale deposits have been known for a long time in Austria, Scotland, Germany, and France.

In 1694 Eele, Hancock, and Poster patented a process of distillation of oil shales [86, p. 1, English patent number 330]. More than 100 years later a patent on oil shale retorting was awarded to A. F. Seligue [86, 91] .

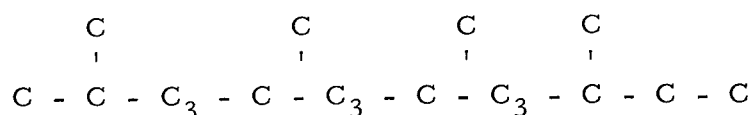
1.2 OIL SHALE CHARACTERISTICS

Oil shales are sedimentary, dry rock formations, occurring to a depth of at least 5,000 feet often interrupted by aquifers. When oil shale rocks are heated above 662° F (350° C) to about 1,000° F, oil and gas substances are released (pyrolysis). The oil content per ton of oil shale rock ranges from 10 or less up to 144 gallons and possibly more. The oil extracted from oil shales differs somewhat from conventional crude oil and is called shale oil. Semantic difficulties exist with regard to which formations may properly be called oil shales [86, pp. 12 ff.] . One does encounter the following geologically different formations so designated [86, pp. 12 ff.] .

- a. Shales partially or completely saturated with oil from an outside source,
- b. Lignite and coaly shales,
- c. Torbernites (contain carbeneous material, otherwise very close to oil shales), kerosene shale and cannel coal (Scotch pronunciation "candle coal"),
- d. Oil shales proper.

Oil shale rock proper is dark brown or gray to black in color. The oil content is obtained from the organic component of the rock (kerogen)

which is intermingled with inorganic substances (ash). Kerogen is chemically subdivided into a relatively small amount of soluble bitumen and larger amounts of insoluble components. Some progress in the chemical analysis of kerogen has been made. The soluble part is related to phytane which has the following chemical structure:



However, much research has yet to be accomplished before kerogen is completely analyzed, especially the insoluble (major) part of it [87].

The Institute of Gas Technology in 1965 gave the following analysis of oil shale, as percent weight of the original rock.

Table 1.1

State	Colorado	Kentucky
Formation	Green River	New Albert
County	Garfield	Marion
Lab. Number	4388	4498
Gallons shale oil per ton	35.9	13.3
Mineral Carbon %	4.96	3.10
Organic Carbon %	17.29	11.17
Hydrogen %	2.42	1.38
Sulfur %	0.71	2.30

FISHER ASSAY:		
Oil Weight %	13.7	5.2
Water %	1.1	0.9
Spent Shale %	82.2	92.0
Gas and Weight loss %	3.0	1.9
	100%	100%

SOURCE: Feldkirchner, Harlan L., "Oil Shale Research Program at the Institute of Gas Technology," Quarterly of the Colorado School of Mines, Vol. 59, No. 3, July, 1965.

Even in rich oil shale basins (25 gallons per ton and more) the oil content will hardly exceed 10 per cent of the oil shale weight, the remainder being mainly spent shale (≈ 90 per cent in weight, 100 per cent and more in volume^{*}) [91]. Oil shale formations in the U. S. exceed a thickness of 1,000 feet ($\approx 2,000$ feet in the Piceance Creek formation, Colorado).

1.3 THE DEVELOPMENT BY NUCLEAR EXPLOSIONS

Both mining and in situ oil shale retorting techniques are at various experimental stages. Both sets of techniques are not yet operated on a large, commercial scale in the U. S. Successful commercial mining operations were and are carried on in some countries (see p. 59 and [86, 92, 93, 94 and others]). A detailed description of the various conventional recovery techniques will not be given here, though in the micro-economic analysis the most optimistic figures in these developments will be compared with potential cost figures by a nuclear in situ development. For additional information the reader is referred to [86, 87, 88, 89, 90, 92, 103, 104, 108, 113, 119, et al.] and for further references to [118].

The major parameters which will affect the economics of nuclear in situ shale oil recovery are:

- a. The particle size distribution within the nuclear chimney which essentially determines feasible retort times.
- b. The area controllable in one retort, be it the combustion pro-

^{*} Oil shale expands when retorted and the extraction of the shale oil has no effect on the volume of the residual spent oil shale.

cess or the gas injection process. The main uncertainties here concern compressor requirements. This determines the size of single retorts, total shale oil recovered from the plant area and its production costs.

c. The thickness of the oil shale formation, which determines the vertical extent of the retorts and the yield of the nuclear devices to be used.

d. The grade of the oil shale.

e. The extent of fracturing around the retorts induced by nuclear explosives. This may affect the amount of shale oil recovered from the non-fragmented oil shale formation (see Figure 1.3).

f. The effective recovery rate of shale oil.

g. The number of retorts which may be combined into one plant.

h. The extent of contamination and seismic hazards.

Major uncertainties--though of different degree--still affect parameters in a, b, e, f, and h.

In order to extract the shale oil, the rock has to be heated to 750° F or higher (retorting), the point at which oil liquifies. To achieve this, mining techniques and above ground retorting can be employed. The hard rock is broken by mining machines, transported to ground surface installations, crushed to small size (about one inch in diameter), and the oil shale is retorted [103, 104]. The shale oil is then either refined locally or transported to centers of demand after preliminary cracking. At room temperatures most shale oils are semi-solid and have a pour point of 75° - 95° F. In mining operations the spent oil shale has to be disposed of as

waste. If an economically comparable technique is developed where the oil is directly extracted from the shales in place (in situ techniques), without having to crush, collect, and transport the oil shale rocks and then dispose of equal quantities of waste products, such a technique is obviously to be preferred to mining operations due to the many economic externalities* that are implied. Nuclear explosions will constitute an essential contribution toward making such a technique economically attractive in deep, thick formations.

The general idea of the development of these resources by means of nuclear explosives is to fracture the rock underground and create a substantial volume of oil shale rubble with an estimated bulk permeability of over 10^6 darcies [120] (See Figure 1.1, from [120, p. 2].) The oil shale rock surrounding the rubble chimney would be relatively impermeable, though fractures might occur out to 4 cavity radii and 7 radii above shot point [see 125]. Air is introduced into the chimney, the top of the oil shale rubble is ignited, and the pyrolysis of the oil shale rock begins, i.e., the chemical breakdown of the kerogen contained in the rock at temperatures between 700° F to 1200° F [114, 115, 117, 131, 132 et al.]. For additional information the reader is referred to [132, 117, 114, 133, 86, 88, 89, 90].

* Economic externalities are benefits which occur within the economic system as a whole but are not reflected in the cost figures or revenue of the particular firm.

The advance of the burning front should be uniform (horizontally) and controlled in its speed of advance. The heat has to be transferred throughout the rock particles in order to recover all the shale oil of the rock particles. As the thermal conductivity of oil shales is very low, this will require a rather slow advance of the burning front in order to retort all of the oil shale. Here the particle size distribution of the rubble is relevant. Other, more important determinants of the effective advance of the burning front are exfoliation and fracturing due to thermal effects. At present only one estimate of the particle size distribution of the oil shale rubble in a nuclear chimney has been advanced, based on an analysis of pictures of a roof fall accident in the oil shale mines at Rifle [120] . These figures are given in Table 1.2.

D. B. Lombard concludes in [120] that the difference between the observed and assumed distributions in Table 1.2 does not significantly influence expected permeability. The assumed distribution in Table 1.2 allows for small particles which could not be observed on the pictures available from the roof fall (shown in [113]). Other uncertainties are likely to have more influence on overall permeability, e.g., whether bulk porosity is 25 per cent or 30 per cent. The latter percentage would increase permeability by nearly a factor of 2 [120, p. 9] .

There are three factors involved in nuclear fragmentation above and beyond that observed in the Rifle mines roof falls:

Table 1.2--Observed* Particle Size Distribution of Oil Shales
in Roof Falls at Rifle Mine, Colorado

Size range (ft)	1/4 - 1/2	1/2 - 1	1 - 2	2 - 4	over 4
Average diameter (ft)	.375	.75	1.5	3	4.5
Number in range	122	98	56	23	4
Fraction in range**	.403	.323	.185	.076	.013

Assumed

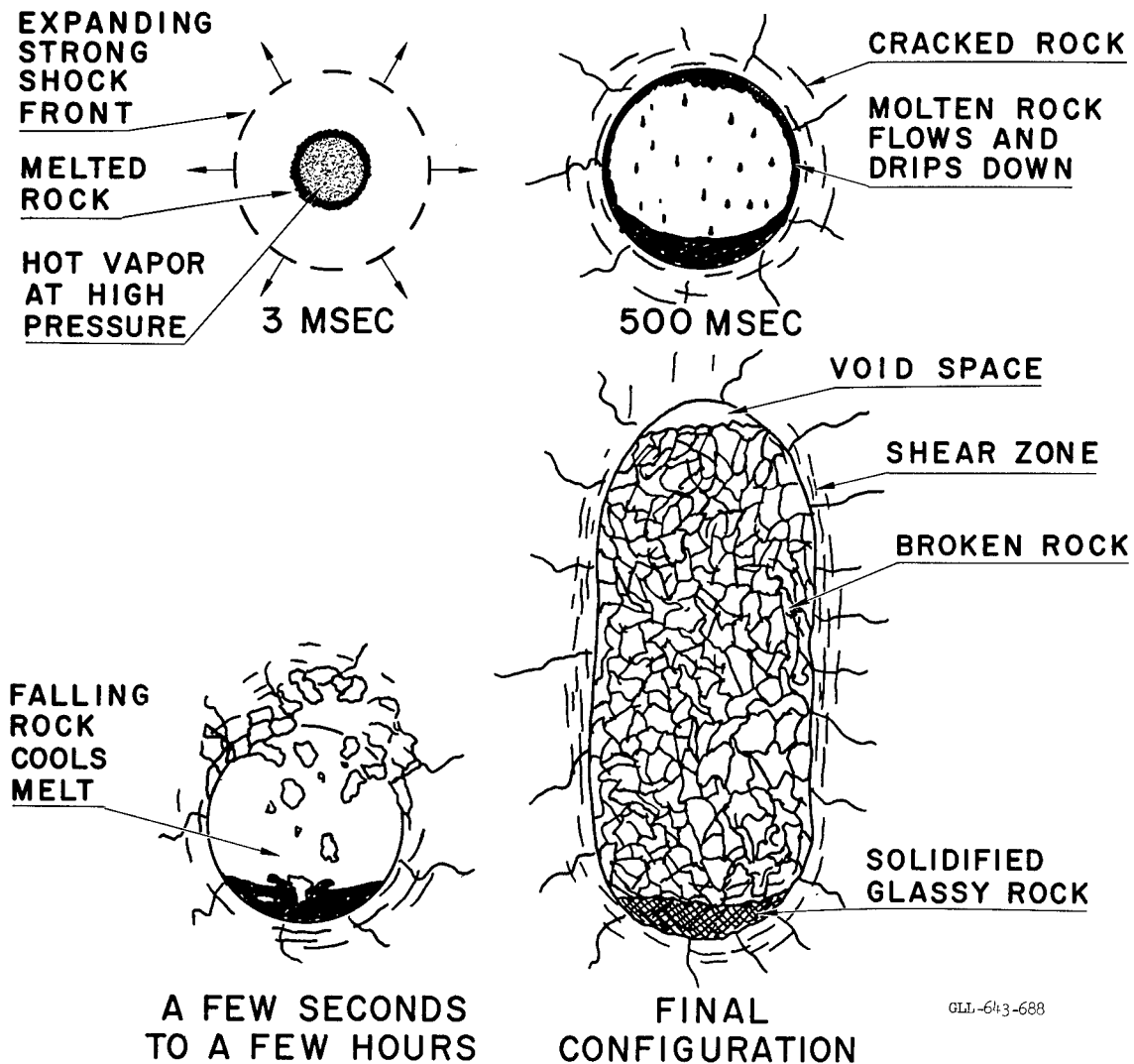
Size range (ft)	0 - 1/4	1/4 - 1/2	1/2 - 1	1 - 2	2 - 4	over 4
Average diameter (ft)	.125	.375	.75	1.5	3	4.5
Number in range	133	401	150	56	23	4
Fraction in range**	.173	.523	.196	.073	.030	.005

* observed on photographs of roof fall fragments

** number in range/total particles counted

SOURCE: Lombard, D. B., "The Particle Size Distribution and Bulk Permeability of Oil Shale Rubble," LRL, Livermore, California, UCRL-14294, August, 1965.

Figure 1.1--Nuclear Chimney Development



SOURCE: Lombard, D. B., "The Particle Size Distribution and Bulk Permeability of Oil Shale Rubble," UCRL-14294, Livermore, California, August, 1965.

a. Oil shale formations already have extensive natural fractures, which even may impede economic commercial mining; the oil shale at the Rifle mines is, however, relatively compact.

b. Phase I and II of the nuclear explosion would create additional extensive fractures [see 125].

c. The average roof fall distance in nuclear chimneys will be larger than roof falls observed in the Rifle mines (on average well above 100 feet against 70 feet at Rifle).

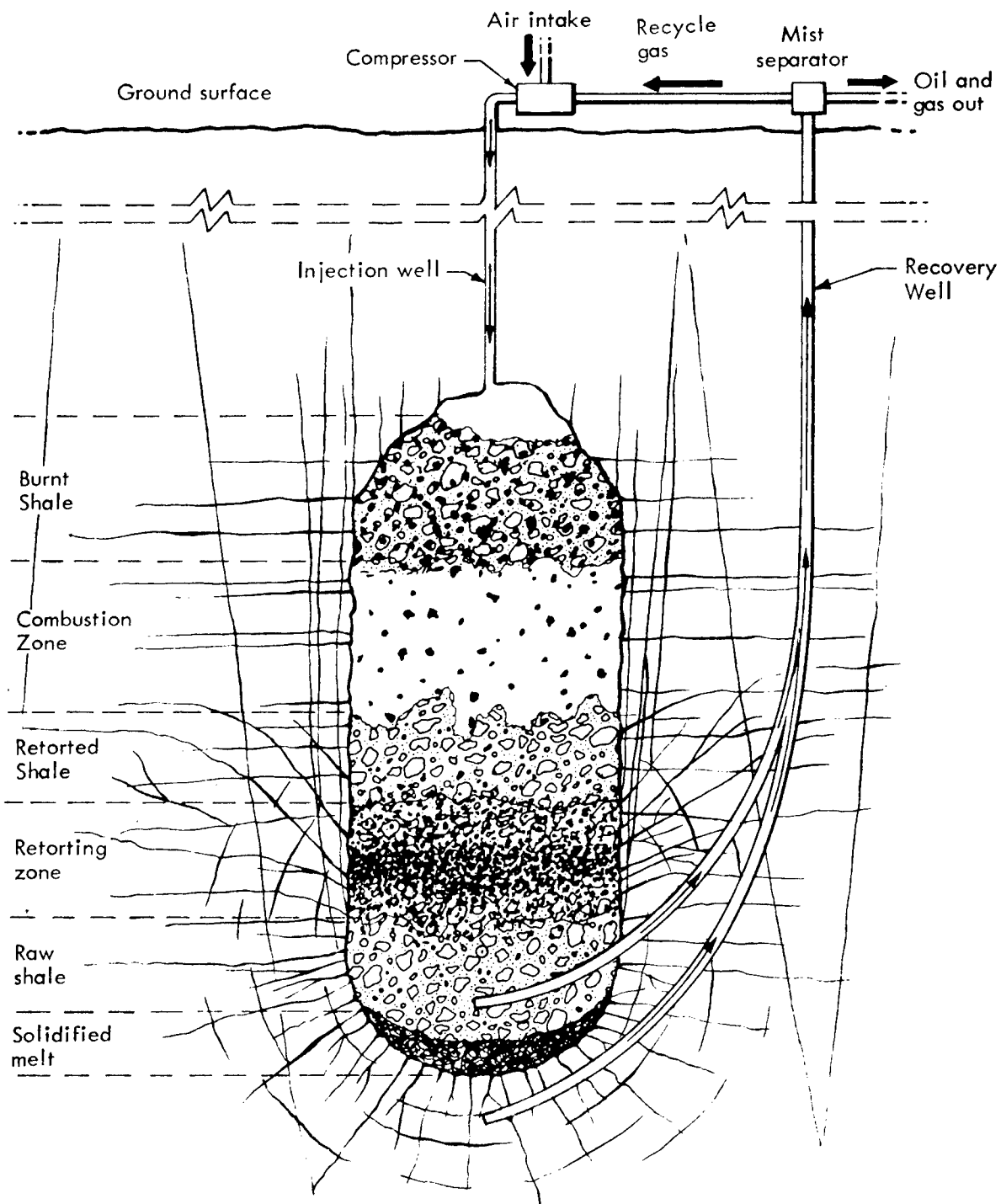
Also, the distributions derived in [120] would be more directly related to "retortability" if the size distribution were given by volume or weight, as in [114, p. 878] for the Hardhat chimney. At the experimental retort of the Bureau of Mines in Laramie, Wyoming, H. C. Carpenter succeeded in retorting random sized particles up to 20 inches in diameter. Nearly all the shale oil was extracted from the particles, and the highest recovery rates observed since January 1966 have been near 70 per cent of the total shale oil content of the rubble input [115]. H. C. Carpenter and D. B. Lombard also observed an average rate of advance of the combustion front as low as 1.7 feet per day. [115, 251]. At 750° F, Carpenter and Lombard estimate that it would require 39 days to retort all the shale oil from particles of 4.50 inches, maximum average particle sizes observed in the roof falls. If retorting temperatures are increased to 850° F, retorting could be completed in about one-fourth the time required at 750° F [115, 251]. All this is based on the assumption that

air and recycle gas are used to retort the oil shale rubble. At present Carpenter's retorts average temperatures of 800° F to 1,200° F quite consistently. (See Figure 1.2, [115, p. 24]).

It is the opinion of D. B. Lombard [120] that particles of any size could be completely retorted if enough time were available. Furthermore, in nuclear in situ retorts, as envisioned in [115, 117, 251], enough time would be available, even allowing for a 75,000 barrels a day (or more) production of shale oil. In large retorts the burning front could advance less than one foot per day. The critical question is, however, whether the uniform advance of the burning front could be maintained if either very large-sized particles or very fine particles interfered with the air and recycle gas flow. This question can only be answered by experiments. The uniform advance of the burning front is desirable in order to avoid the burn-up of shale oil in the retorting process. It is expected that most of the energy required would be provided by the residual carbon in the oil shale rocks, while the shale oil is recovered before the burning front reaches deeper regions (see V. D. Allred, [134]).

In case the in situ retorting by underground combustion poses serious problems, other techniques to retort the underground chimney seem now to be available: for instance, the Equity process of hot methane injection and recycling of those gases [131, 132]. Partial cracking may occur in both retort processes. In the Equity process, using methane, high-grade oil was recovered. As no combustion does occur in this latter

Figure 1.2--In Situ Retorting Procedure for
a Nuclear Chimney in Oil Shale



SOURCE: Lekas, M. A., and Carpenter, H. C., "Fracturing Oil Shale with Nuclear Explosives for In Situ Retorting, Second Symposium on Oil Shale," *Quarterly of the Colorado School of Mines*, 1965, Vol. 60, No. 3.

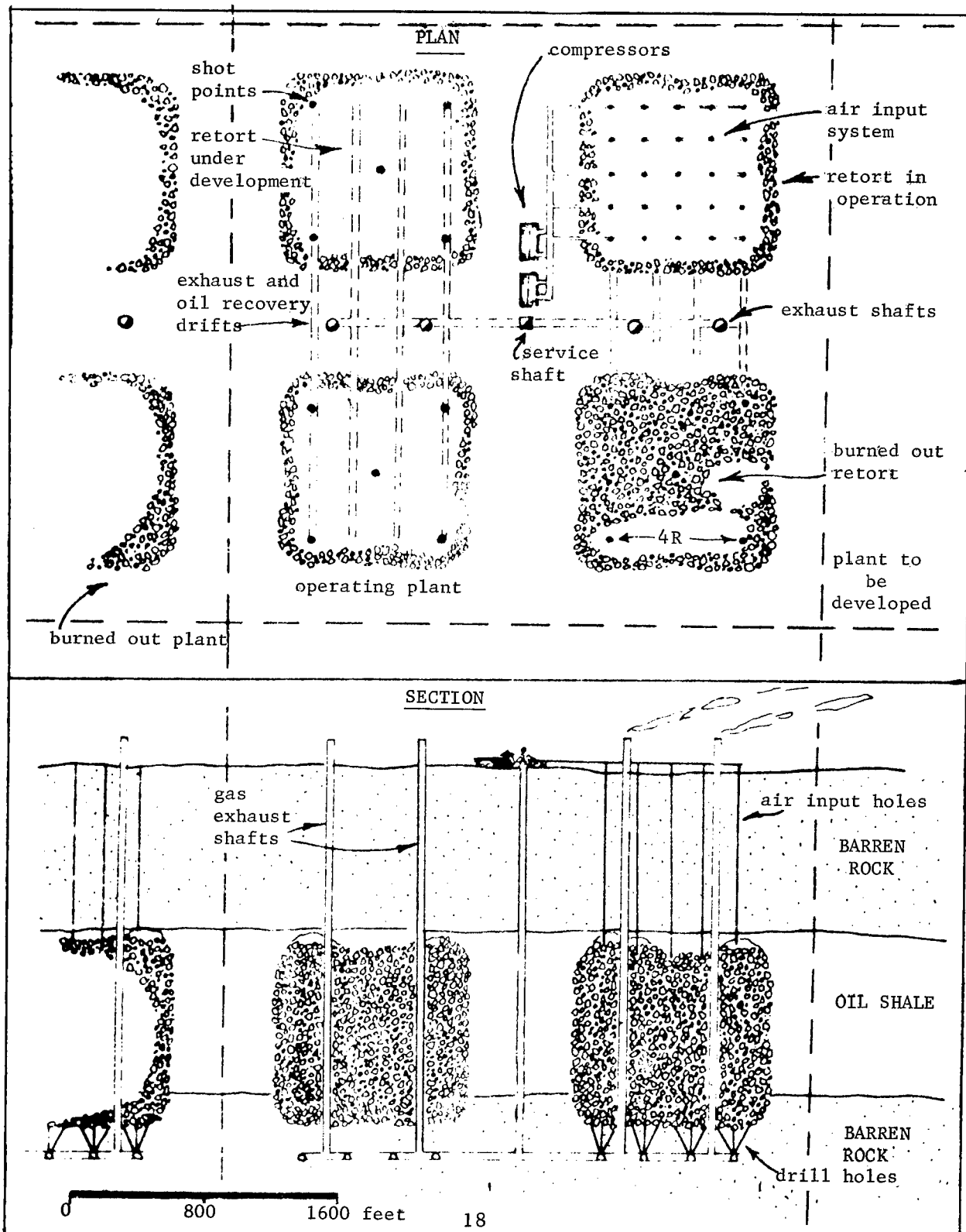
process (the gas is heated above ground) theoretically all of the oil shale of the chimney could be retorted. Some other problems that may occur in the former process are also potentially avoided: the conversion of the kerogen, its distillation and removal from the shale by the hot methane (natural gas), produces a porous structure which allows the process to continue through the formerly non-porous oil shales. In combustion processes the spent shale tends to fuse, at least partially, which might lower their recovery rates (see Carpenter and Lekas [115]). In both cases one might also expect some recovery from the fractured zone around the nuclear chimney [see 125] . To utilize fully the in situ nuclear technique, a recovery process from the fractured zones between retorts seems very desirable (see microeconomic section).

If the combustion zone could be controlled independently of the size of the rubble area, then the most direct way to develop the oil shale resources would be to reduce the whole oil shale bed to rubble. All the oil shale, or at least a large percentage of it, would then be recoverable.

However, in both cases (combustion, hot gas injection) one may have to confine retort operations to technically controllable areas.

If areas of 1,200 x 1,200 feet are controllable (≈ 35 acres), then four retorts may be combined in one plant. In the layout of M. A. Lekas [117, p. 10] (see Figure 1.3), this would require an area of about 400 acres, which means that only 40-50 per cent of the available oil shale bed is fractured and that only part of the shale oil contained in this rubble

Figure 1.3--Layout of a Commercial Scale Nuclear In Situ Retorting Plant for 1,000 ft. Thick Shale Bed



SOURCE: Lekas, M. A., "Economics of Producing Shale Oil--the Nuclear In Situ Retorting Method," Third Symposium on Oil Shale, Quarterly of the Colorado School of Mines, Vol. 61, No. 3, July, 1966.

(75 per cent, Lekas) is recovered. Nevertheless, if all the other built-in assumptions are correct, then a strong case is made for developing this technique (see below, Chapter 3). At this point one has, however, to remind oneself that the primary and secondary recovery rates from crude oil reservoirs is only 30 per cent and 50 per cent (cumulative) of the oil in place.

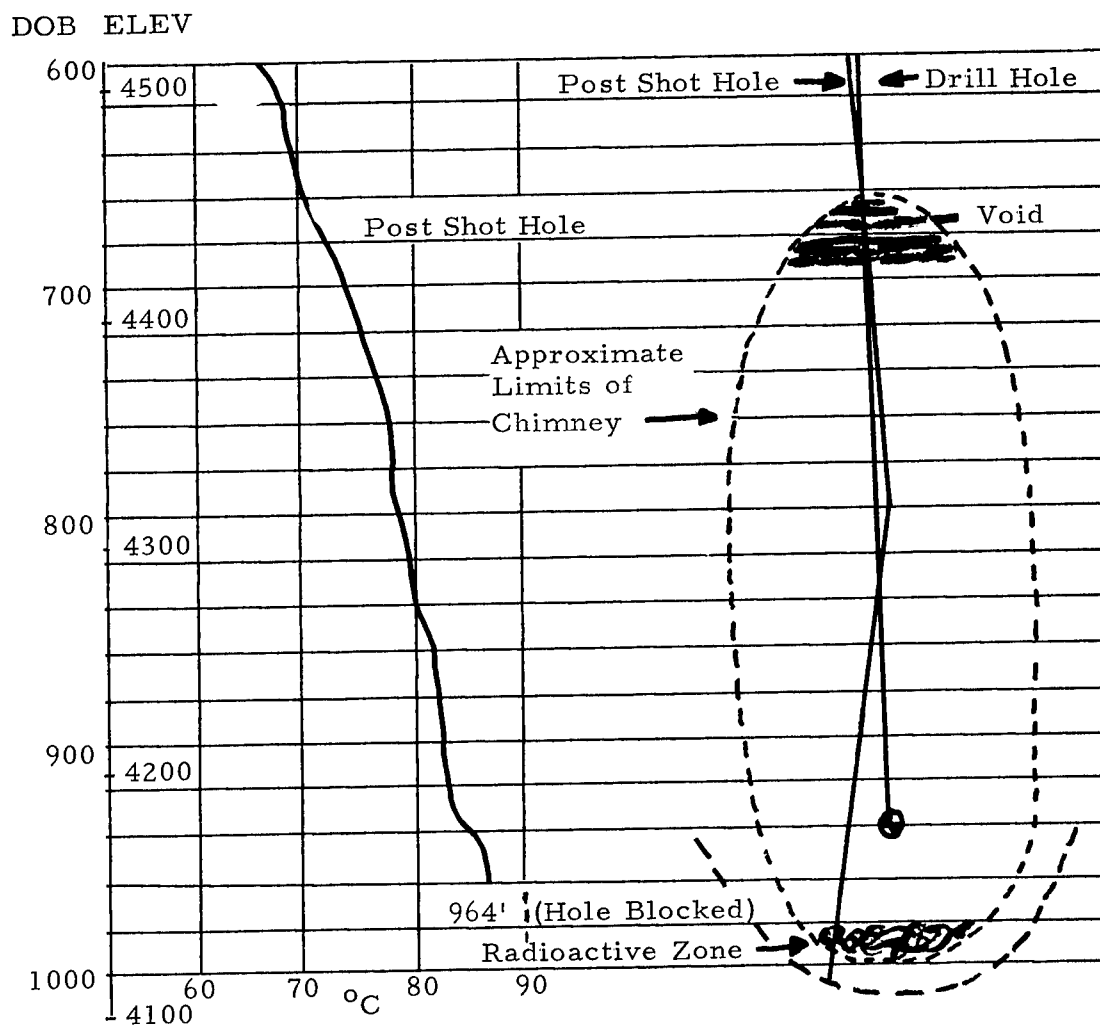
Through heat transfer one would even expect to recover at least part of the shale oil in the "pillars", as these are considerably fractured by the explosion. Secondary recovery techniques, relating to the pillars, may also be developed by burning the shale from one retort to the next. Also, the non-fragmented area may be reduced by a different grouping of the retorts or reductions in feasible pillar sizes for retort control.

An aspect peculiar to nuclear explosions may enhance the economic feasibility of the in situ process: the temperature increases throughout the chimney and especially around shot point (above 100° F and 200° F, respectively). (See [125], [41] general report of MATHEMATICA, and Figure 1.4).

The heat distribution within the chimneys of past experiments is summarized in Table 1.3 [41, p. 293] .

The temperature increases exceed the pour-points of shale oil (70° - 90° F, 30° C) considerably in all events except the small Neptune shot . This would allow the shale oil to flow to its collection system at the bottom of the retort and could facilitate the retorting itself by lowering

Figure 1.4--Hardhat Temperature Profile 11 Months after Shot Time;
(Pour Point of Oil Shale $\approx 30^{\circ}\text{C}$ or $\approx 90^{\circ}\text{F}$)



TEMPERATURE LOG

DATED 1-20-63 (H+11 MONTHS)

PROFILE

SOURCE: Heckman, R. A., "Development of Therman Energy by Nuclear Explosives," LRL, Livermore, California, Third Plowshare Symposium.

Table 1.3

Event	Yield in KT	Medium	Depth of burial (feet)	Thermal Energy Residual (fractions)	Max. temp. observed (° F)	Time of measurements after shot time (months)
Neptune	.115	tuff	99	-	69	6
Blanca	19.	tuff	835	0.069	122	4
Logan	5.0	tuff	830	0.23	185	6
Rainier	1.7	tuff	790	0.23	194	5
Tamalpais	.072	tuff	330	-	127	3
Gnome	3.0	salt	1,184	0.95	181	6.5
Hardhat	4.5	granodiorite	939	0.41	190	11
<u>Shoal</u>	<u>12.5</u>	<u>granodiorite</u>	<u>1,205</u>	<u>1.07</u>	<u>1098</u>	<u>2.5</u>

SOURCE: Heckman, R. A., "Development of Thermal Energy by Nuclear Explosives," LRL, Livermore, California, Third Plowshare Symposium.

the additional heat requirements. Carpenter and Lekas [115] expect that the heated shale oil will advance the retorting area well beyond the combustion zone such that, given present evidence, all the shale oil would be retorted when the combustion zone reaches half way through the nuclear chimney.

The contamination problem may be less serious than in the case of gas stimulation [125]. The comparison of oil shale in situ retorting with gas stimulation in the light of this problem would appear favorable if the following conditions hold:

- a. About 90 per cent of the total radioactivity created is trapped in the glass melt of the fused rock material around shot point. Most of the refractory nuclides are trapped in this way [62, 63, 64, 65, 66, 67].
- b. Volatile nuclides can be vented soon after the explosion and collected above ground, though at additional cost.
- c. The shot point of the explosion can be placed below the oil shale formation and, as Piper proposed [1], sealed off, if necessary.
- d. Minimization of the contamination problem by particular shielding of the device in oil shale applications. Effective shielding may differ substantially between different types of applications of nuclear explosives.

In addition, some of the tritiated oil could be used, for example, in a power generating plant where human contact with the tritiated oil is

avoided. The tritium exchange is accelerated at higher temperatures, thus some cost may be caused by tritiation [71, 72].

Most of the above points would involve certain costs which, however, are not expected to be substantial by present knowledge. Similarly, one may prevent adverse seismic effects by an adequate construction and development program of the oil shale plants. Potential damage may be caused to pipelines and some retort facilities in large explosions. The "Mudpack" shot, however, showed that damage to nearby pipelines was minimal. Certain construction techniques would allow a further reduction in potential damage to pipelines and drill holes.

Finally, the nuclear in situ scheme requires only a limited amount of personnel as compared to the relatively high labor requirements in mining and retorting operations. This substantially diminishes water requirements of large nuclear shale oil operations. Fifty per cent of the water requirements in conventional processes are due to personnel requirements [108, 113, 135, 136, et al.].

Table 1.4 details labor demands for conventional operations.

Table 1.4--Personnel Requirements in Conventional Operations

Permanent Personnel	25, 000 Barrels/Day	150, 000 Barrels/Day	1, 250, 000 Barrels/Day
	(Number of Persons)		
Production *	900	6, 900	50, 000
Construction **		1, 500	9, 000
Other industrial			1, 000
	900	8, 400	60, 000
Service personnel (new)	360	7, 100	53, 500
Households (new)	630	12, 500	93, 000
New population ***	2, 300	45, 000	340, 000

* 500 production workers from existing local population

** Prototype construction personnel local or temporary; 1/2 construction personnel for expansion permanent.

*** 3.6 persons per household

SOURCE: East, J. H., and Gardner, E. D., Oil Shale Mining, Rifle, Colorado, 1944-56, U. S. Bureau of Mines, Bull. 611, Wash., D.C., 1964.

In in situ operations it may occur that an excess of water (aquifers) in the formations will pose more problems than the scarcity of water.

This labor "extensive" and water "extensive" in situ technique has to be evaluated against other, conventional, techniques in a water-scarce and population-scarce region (NW Colorado, N Utah, SW Wyoming). J. H.

East and E. D. Gardner anticipate the following water requirements for 25,000 barrels a day, 150,000 barrels a day, and 1.25 million barrels a day conventional oil shale plants [113, p. 161-163] (see Table 1.5).

Other similar estimates were advanced more recently: 110,000-220,000 acre-feet per year for a conventional 2 million barrels a day plant [136], 455,000 acre-feet for a 2 million barrels a day plant [108], of which 165,000 acre-feet would be consumed.

Should oil shale become a major energy base for the U. S. economy a production of 5-10 million barrels a day will be an adequate production level, with proportionally increasing water and labor requirements. The total available water of the whole Upper Basin States is, however, only 5.6 million acre-feet per year of which only 2.5 million acre-feet per year are Colorado's share [137]. Any water diverted and consumed is in the main part lost for other projects (mainly irrigation, other potential industries), and this constitutes high "opportunity costs" for any water diverted to shale oil production in the future.

Another aspect of the nuclear in situ method must be mentioned: nuclear shale oil plants of any size and number can be created within a short time, as the oil shale deposits are known and emplacement facilities can be constructed far in advance. This would allow the United States to expand its oil production deliberately, and if carefully planned in advance, such production could be substantially expanded within a matter of months should such a need ever arise. But for this and other reasons,

Table 1.5--Water Requirements Per Year in Acre Feet

	25,000 Barrels/Day	150,000 Barrels/Day	1,250,000 Barrels/Day
Production and refining			
diverted	550	12,000	127,000
consumed	500	11,000	114,000
Shale related industry			
diverted			10,000
consumed			5,000
New population			
diverted	750	15,000	115,000
consumed	250	5,000	40,000
Total			
diverted	1,300	23,000	252,000
consumed	750	16,000	159,000

SOURCE: East, J. H., and Gardner, E. D., Oil Shale Mining, Rifle, Colorado, 1944-56, U. S. Bureau of Mines, Bulletin 611, Washington, D. C., 1964.

mentioned above and below, nuclear in situ production technologies have first to be developed and tested by experiments and by pilot plants.

Chapter 2

MACRO-ECONOMIC POTENTIAL OF SHALE OIL RECOVERY BY NUCLEAR EXPLOSIVES

2.1 U. S. CRUDE OIL RESOURCES

The difficulty of obtaining reliable data encountered in MATHEMATICA's report on gas stimulation extends equally to the data encountered on conventional crude oil reserves, both in the U. S. and the World. Even if semantic difficulties are overcome, the estimates still have a range which points to their highly speculative character, in many ways a sort of "Bayesian estimate" of the DELPHI - type method [105]. If we apply the strict definition of the American Petroleum Institute (A.P.I.), one is likely to use misleading and quite pessimistic interpretations. A.P.I. reserve estimates are based on the following definition: "Proved reserves are both drilled and undrilled. The proved drilled reserves, in any pool, include oil estimated to be recoverable by the production systems now in operation, whether with or without fluid injection, and from the area actually drilled up on the spacing pattern in effect in that pool. The proved undrilled reserves, in any pool, include reserves under undrilled spacing units which are so close, and so related, to the drilled units that there is every reasonable probability that they will produce when drilled." [20, p. 387, footnote]. Under this definition the reserves were persis-

tently in the range of 11 to 13 times of the corresponding annual production figure of oil. The development over the last decades is shown in Table 2.1 [20, p. 389 and 112, p. 4 and p. 11].

Table 2.1

	U. S. A. Crude Oil Production (in 10 ⁶ barrels)	End of year proved reserves	Multiple of Annual Production
1944	1,678	19,784	11.8
1949	1,819	24,649	13.6
1954	2,257	29,651	13.1
1959	2,483	31,719	12.8
1964	2,805.125*	30,991	11.0

* U. S. Department of Interior Figure.

SOURCES: Landsberg, H. H., Fischman, L. L., and Fisher, J. L., Resources in America's Future - Patterns of Requirements and Availabilities, The Johns Hopkins Press, 1962.

Kirby, James G., and Moore, Betty M., "Crude Petroleum and Petroleum Products," Bureau of Mines Mineral Yearbook 1964, Bureau of Mines, Washington, D. C., 1965.

It suffices to say that up to now (mid 1966) 80×10^9 barrels of crude oil have already been produced (cumulative production), i.e., four times the 1944 estimate and about three times the 1964 estimate. In this light any comment on the accuracy of "End of year proved Reserves" down to five digits (1964: $30,991 \times 10^6$ barrels) may be omitted. Even more distressing is Table 2 in [112, pp. 3-5] where three pages covering 1962-64 demand and supply figures are given consistently down to seven digits

of which only the 1964 production figure is cited here. The cost involved in printing and reprinting all these useless digits from the third one onward certainly exceeds the value of any information to be derived from them (another example of the "accuracy" of economic observations to be added to [109]).

Current annual crude oil production runs around 3×10^9 barrels and, pending no increasing resource restraints, demand and supply for crude oil could more than double by the year 2000 A.D., given past developments, to an annual figure of 7 to 10×10^9 barrels. Present A.P.I. reserves would be exhausted in less than 10 years. This gave rise to other estimates of a more speculative character. Any estimates of recoverable domestic resources and reserves have to cope with three problems:

- a. the physical amount of oil present underground,
- b. the techniques of recovery, whereby one may assume that no technological progress will occur (static assumption) or one may allow for some improvements, which in their very nature are highly speculative, e.g., secondary recovery, higher prime recovery rates, etc.
- c. the costs the economic system is prepared to sustain in order to search for and recover this resource.

In some of the estimates it is not quite clear which assumptions were made with regard to the one or the other factor or both. Differences are often

due to semantic variations. Furthermore, there seems to exist some "feedback" among most of these estimates.

Paul D. Torrey [98] estimates the primary oil content of known U. S. reserves to be 328×10^9 barrels, of which 63×10^9 had already been recovered (80×10^9 by early 1966). Of these 328×10^9 about 50 per cent were assumed to be recoverable, i.e., 164×10^9 , which would imply that by now 50 per cent of all recoverable reserves of the U. S. would have been exploited, leaving 84×10^9 underground. This estimate takes account of some technological progress but covers only known, explored acreage.*

Sam H. Schurr, Bruce C. Netschert, Hans Landsberg ("Resources for the Future") adhere to a 500×10^9 barrels of oil physically still present underground awaiting future recovery [20, 92], i.e., not taking into account past recoveries (63×10^9 barrels at that time). Allowing for different rates of technological progress, $2/3$, $1/2$, and $1/3$ (static technology) recovery rates are considered and would lead to 330×10^9 barrels, 250×10^9 barrels and, at present techniques, 176×10^9 barrels of recoverable crude oil left underground [20, pp. 390 ff.].

Lewis G. Weeks estimates overall liquid hydrocarbons in existence (crude oil and liquid natural gas) at 400×10^9 barrels, of which 60×10^9 barrels were already recovered, another 60×10^9 barrels were gas liquids, leaving 340×10^9 barrels underground [27] "Resources for the Future" judged that this estimate was "in the same ball park" (160×10^9 barrels

* Since then P. D. Torrey has made a more recent evaluation of 400×10^9 of original oil in place [250].

difference, about 50 per cent of Weeks estimate) which throws some additional light on the accuracy of these figures.

A. D. Zapp [96] indicated that ultimate reserves may go well beyond the 500×10^9 barrels mark (in fact 590×10^9 barrels) encouraging the "Resources for the Future" to speculate that their 250×10^9 recoverable reserves were 50 per cent of 500×10^9 (their basis), 45 per cent of 550×10^9 and 40 per cent of 625×10^9 barrels of oil physically underground.

M. K. Hubbert [26, p. 72] estimated total ultimate U. S. production around 175×10^9 barrels, allowing for some technological progress and offshore production. The Zapp estimate was known to Hubbert: this estimate implies therefore that by now over 50 per cent of the recoverable reserves have been already produced.

C. L. Moore estimates in-place oil reserves at 486×10^9 barrels and oil ultimately recoverable at 364×10^9 barrels. All of the above-mentioned estimates do not include Alaska [110].

V. E. McKelvey and D. C. Duncan [111] adhere to the 590×10^9 barrels Zapp estimate and break it further down into "known recoverable reserves" of 48×10^9 barrels, "undiscovered recoverable resources" of 200×10^9 barrels, "known marginal resources" of 40×10^9 barrels and "undiscovered marginal resources" of 300×10^9 barrels.

An interesting argument is advanced by T. A. Hendricks on future discoveries of crude oil in the United States [11, pp. 7 ff.]. Present

reserves in explored acreage to be explored are given by Hendricks as six times the present acreage with a yield of only 50 per cent of reserves per acre known to exist in the explored area. This leads to the estimate of:

$$\frac{400 + 400 \times 6}{2} = 1,600 \times 10^9$$

barrels of crude oil present in explored and unexplored areas. These $1,600 \times 10^9$ barrels are then further qualified as follows: total in place $1,600 \times 10^9$ barrels, total in place to be found by exploration $1,000 \times 10^9$ barrels, economically recoverable (40%) 400×10^9 barrels, sub-marginal $1,200 \times 10^9$ barrels (undiscovered or uneconomic). A 40 per cent recovery rate already allows for some technological progress, but ultimate technically possible recovery rates might well be higher. A $2/3$ recovery rate is the most optimistic rate mentioned by "Resources for the Future," and would then yield about 630×10^9 barrels of crude oil, of which 80×10^9 barrels were produced by early 1966. Table 2.2 summarizes T. A. Hendricks' estimates.

In whichever way we look at these figures, we may conclude with some confidence that about 500×10^9 barrels are the maximum recoverable crude oil reserves, allowing for considerable technological progress. A figure around 400×10^9 barrels or 350×10^9 barrels seems to be more realistic, i. e., about five times the cumulative U. S. production by

Table 2.2-- Oil, Gas, and Natural-Gas Liquids
Originally Underlying the United States
(Highest Estimate)

	Crude Oil 10^9 Barrels	Natural Gas 10^{12} Cubic Feet	Natural Gas Liquids 10^9 Barrels
Total in Place	1,600	4,000	120
Total in Place to be Found by Exploration	1,000	2,500	75
Economically Recoverable	400	2,000	60
Submarginal	1,200	2,000	60
Approximate Production through 1961	68	230	6-7

SOURCE: Hendricks, T. A., "Resources of Oil, Gas, and Natural Gas Liquids in the U. S. and the World," U.S. Dept. of the Interior, GSC 522, 1965.

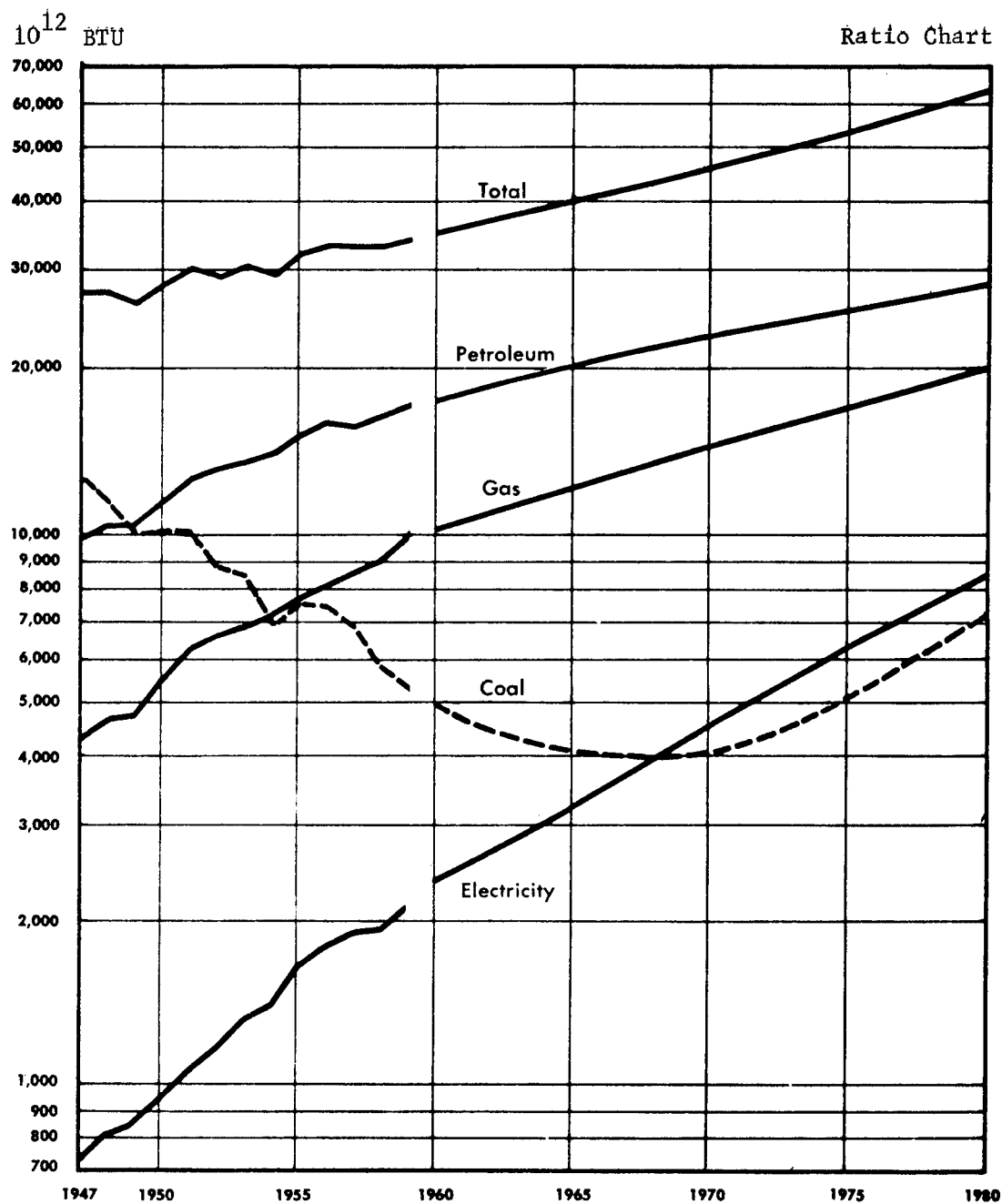
mid 1966 and leaving roughly 300×10^9 barrels of recoverable crude oil underground, and in the more optimistic case 420×10^9 barrels.

Allowing for some increase in demand for oil from 3×10^9 to $7-10 \times 10^9$ barrels in about one generation, it appears to be very likely that around the year 2000 conventional crude oil resources will face a critical situation. (See Figure 2.1 [150, p. 17].)

Past experience has shown, however, that statements with regard to the exhaustion of oil reserves have often proved to be understatements. From the above presentation similar evidence can easily be constructed, e.g., the fact that up to the beginning of 1966 four times the 1941 proved reserve estimate of A.P.I. was actually produced. However, the above statements

Figure 2.1--Energy: Sources of Supply

1947 - 1980



SOURCE: Texas Eastern Transmission Corporation, "Energy and Fuels in the United States 1947-1980," Houston, Texas, July, 1961.

also make it clear that the year 2000 projection is optimistic. We assume here a U. S. potential of crude oil production of $350-400 \times 10^9$ barrels, of which, however, only 48×10^9 barrels are "A.P.I." and "IOCC" proved. If the present 3×10^9 barrels a year production is expanded by then to 10×10^9 barrels, it would leave by the year 2000 a 13-year production reserve of $150-200 \times 10^9$ barrels at best. And one has to emphasize that under present techniques, such a production would require at least $1,000 \times 10^9$ barrels underground discoverable reserve (50 per cent recovery, including secondary recovery and other likely improvements), while most estimates are considerably under this mark. All this, of course, holds only under the assumption that oil shales are not developed and that the present energy source structure is maintained. One might object to this that developments of foreign markets might allow the U. S. to pursue an adequate reserve policy by importing substantial amounts. However, the above projection already includes a 20 per cent import quota [99]. In the long run a 20 per cent import quota might even be an overestimate, given the potential development of other and new industrial nations and given that U. S. reserves themselves constitute a considerable amount of world reserves. Of this U. S. potential ($500-600 \times 10^9$ maximal), only about 50×10^9 barrels have been proved according to "IOCC" definition (31×10^9 barrels in primary recovery of Table 2.1 and an additional 16×10^9 in expected secondary recovery, probably economic under present conditions) [106].

2.2 WORLD CRUDE OIL SITUATION

The distribution of world production over various countries in 1965 is shown in Table 2.3 (in 10^6 barrels) [148, p. 120].

Table 2.3--World Production 1964-65
in 10^6 Barrels

	1965	1964	Change in %
North America	3,259	3,177	+ 2.9
Middle East	3,030	2,787	+ 9.2
East Europe*	1,897	1,758	+ 8.2
South America	1,514	1,481	+ 2.5
Africa	816	623	+31.2
Others	small	small	-
	10,987	10,264	+ 7.3

* Includes U.S.S.R. production
SOURCE: World Oil, February 15, 1966.

It is estimated that the Middle East alone contains 60 per cent of the world reserves (1960 estimate). However, these figures are subject to constant change. African, Chinese, and North Sea deposits alone could alter this picture considerably.

The tendency toward gas and oil fuels in developed economic areas is also revealed by the respective developments in the U. S. A. and

U. S. S. R. [100] given in Tables 2.4 and 2.5, and the world (See Tables 2.6 and 2.7).

Table 2.4

	U. S. S. R.			U. S. A.	
	1953	1960	1965	1953	1960
Coal (10^6 t)	320	513	612	443	388
Oil (10^6 t)	52.8	148	240	319	347
Gas (10^9 m ³)	8.0	47.2	150	242	346

SOURCE: Planovoe, Khozyaystvo, No. 5, May, 1961, p. 65.

In the U. S., petroleum supplied 44 per cent, natural gas 29 per cent of the U. S. energy demand in 1962 [101] (see Table 2.5 and Figure 2.1).

Of interest also is how total energy demand develops in the U. S. and the projections for 1980 made by the U. S. Department of Interior and by the U. S. Federal Power Commission in 1964. The Federal Power Commission projects a 1980 U. S. energy demand of $82,000 \times 10^{12}$ Btu [59, p. 37]; the Department of the Interior gives a roughly identical estimate of $85,000 \times 10^{12}$ Btu if we convert the 38.8×10^6 barrels daily of crude oil equivalents with 6×10^6 Btu per barrel ($365 \times 38.8 \times 6 \times 10^6 \times 10^6$). [24, p. 3a]. (See Figure 2.1) Tables 2.5 and 2.6 give estimates and projections of energy demands in the U. S. and the world as seen by the Department of the Interior [24, p. 3a, p. 3b]:

Table 2.5--Estimated Total Energy Consumption in the U. S.

in 10⁶ Barrels Daily of Crude Oil Equivalents

	1930	35	40	45	50	55	60	65	70	75	1980
Hydro	.4	.4	.4	.7	.8	.7	.9	1.0	1.1	1.2	1.2
Coal	6.4	5.0	5.9	7.6	6.1	5.5	4.9	5.4	6.6	8.4	10.5
Oil	2.8	2.7	3.6	4.8	6.4	8.3	9.4	10.7	12.0	13.4	14.9
Natural Gas	0.9	0.9	1.3	1.9	2.9	4.3	6.0	7.2	8.5	9.8	11.3
Nuclear	-	-	-	-	-	-	-	-	.2	.4	.9
TOTAL	10.5	9.0	11.2	15.0	16.2	18.8	21.2	24.3	28.4	33.2	38.8

SOURCE: U. S. Department of the Interior, "The Oil Shale Problem," A synopsis prepared for the opening meeting of the Department of the Interior, Oil Shale Advisory Board, July, 1964.

Table 2.6--Estimated World Consumption of Primary Commercial Energy
 10^6 Barrels Daily of Crude Oil Equivalents

	ACTUAL						FORECAST		
	1929	37	50	55	60	65	70	75	1980
Hydro	1.5	1.9	3.1	2.8	4.2	4.7	5.2	5.7	6.1
Coal	21.6	21.4	24.3	27.8	33.8	37.3	39.2	41.1	44.9
Oil*	4.3	5.8	10.8	16.0	21.9	31.8	43.6	55.7	62.7
Nat. Gas	1.1	1.6	4.2	6.0	9.4	13.2	17.5	24.6	35.4
Nuclear	-	-	-	-	-	-	.5	.9	1.9
	28.5	30.7	42.4	52.6	69.3	87.0	106.0	128.0	151.0

SOURCE: U. S. Department of the Interior, op cit.

In percentage this projection implies the following U. S. and world development:

Table 2.7

	U. S. A.			WORLD		
	1960	65	80	60	65	1980
Coal	24	23	28	50	43	30
Oil	45	44	38	31	36	40
Natural Gas	30	30	30	13	17	24
Others	1	3	4	6	4	6
	100	100	100	100	100	100

* Includes: Crude Oil, Natural Gas Liquids, Shale Oil and Synthetic Oils.

If we consider that oil and gas contribute today 75 per cent of the overall energy supply in the U. S. and about 50 per cent of world supply and if we further attribute some confidence in the future development of energy demand as expressed in Tables 2.5 to 2.7, then oil reserves and natural gas reserves tend to assume considerable importance, and with them, also, shale oil reserves. This statement, together with the previous analysis, is underlined if we consider the total fossil reserve picture of the U. S. and the World, even granted that some of the figures might turn out to be quite inaccurate (derived from [24, p 6] and Table 2.13).

2.3 U. S. SHALE OIL RESOURCES

In the previous chapter U. S. crude oil resources were analyzed. We may conclude that, even under the most optimistic estimates, a shortage in crude oil reserves will develop within the next generation (up to the year 2000) if the energy demand is supplied as it has been up to now, i. e., by fossil fuels and within this, again, mainly by oil and gas. In the report on gas stimulation [125], we expected to extend the available gas supplies by nuclear stimulation by an additional 18 to 45 if not more years, i. e., within the economic history of a nation at best a medium range extension.

Present conventional crude oil supplies may be adequate for a similar period of time (30-40 years), allowing for considerable technological progress (e. g., nuclear stimulation). But we cannot recover more oil from a given area than is physically present there, and even given the past experience of production and reserves, oil reserves are finite

and some upper limit is in sight now. Shale oil reserves are therefore important for at least two reasons:

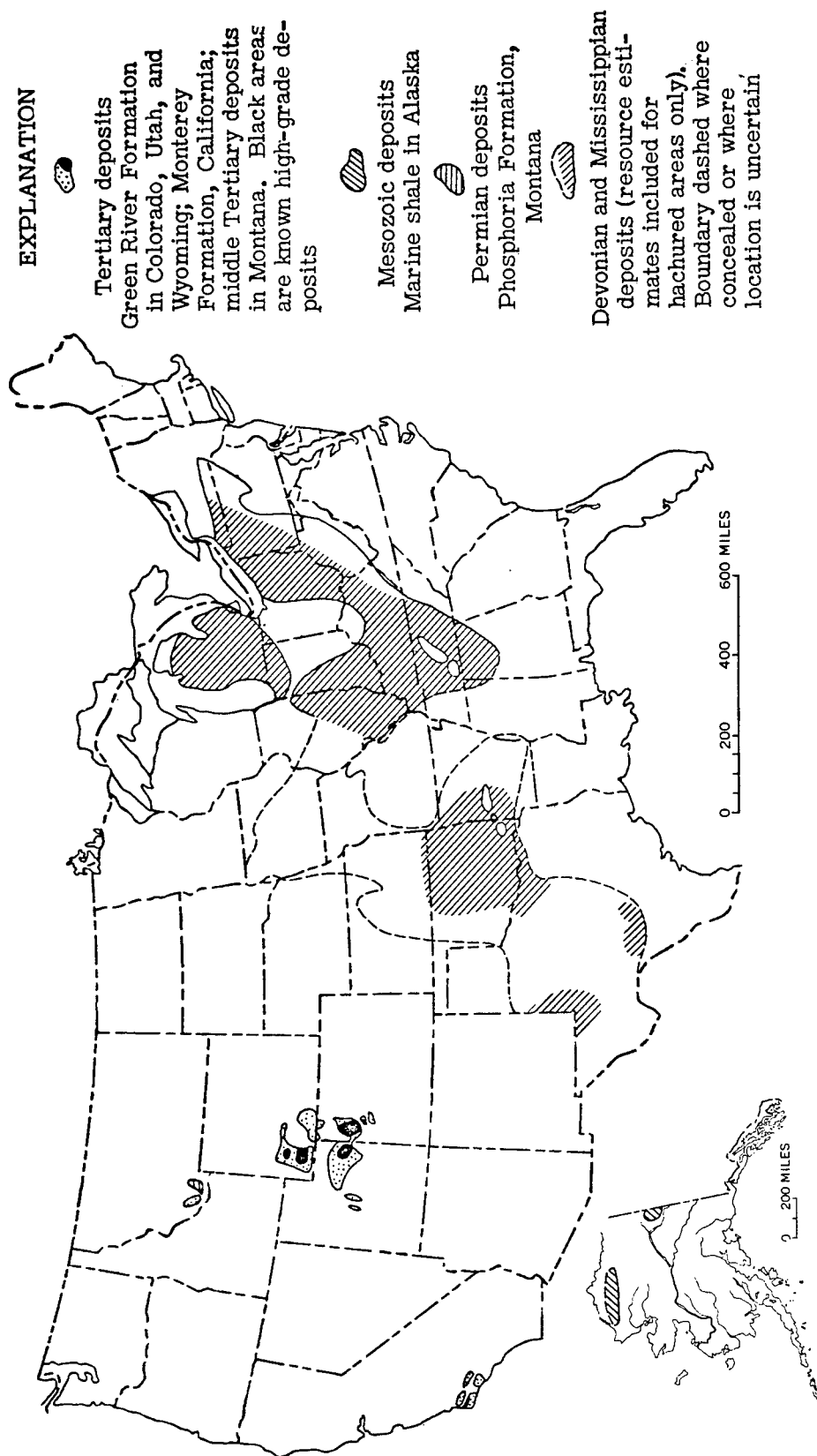
a. As potential extensions of U. S. oil reserves, once serious shortages in the crude oil section develop.

b. As potential competitors with conventional oil supplies at prices below even "ultimate" conventional crude oil prices at present production rates (See microeconomic section.)

Deposits of oil shales are known to exist in Colorado, Nevada, Utah, Wyoming, Indiana, Kentucky, Pennsylvania, West Virginia, and other states [30, 113, 121, 122]. The geographical distribution is shown in Figure 2.2 [30] while Figure 2.3 shows the main U. S. oil shale deposit in more detail. In a broad generalization we may define two major areas of oil shale basins in the U. S.: the Green River formation in the Rocky Mountains (See Figure 2.3), the largest proven oil shale deposit in the world, and the area of the Devonian and Mississippian shales of the Eastern and Central United States [30, 91, 113, 123, 124, et al]. In addition to these reserves, high grade oil shale deposits exist in Alaska (up to 140 gallons of shale oil per ton of oil shales), but the extent of these deposits and their characteristics are yet unknown. Undiscovered* oil shale deposits also exist in other parts of the U. S.,

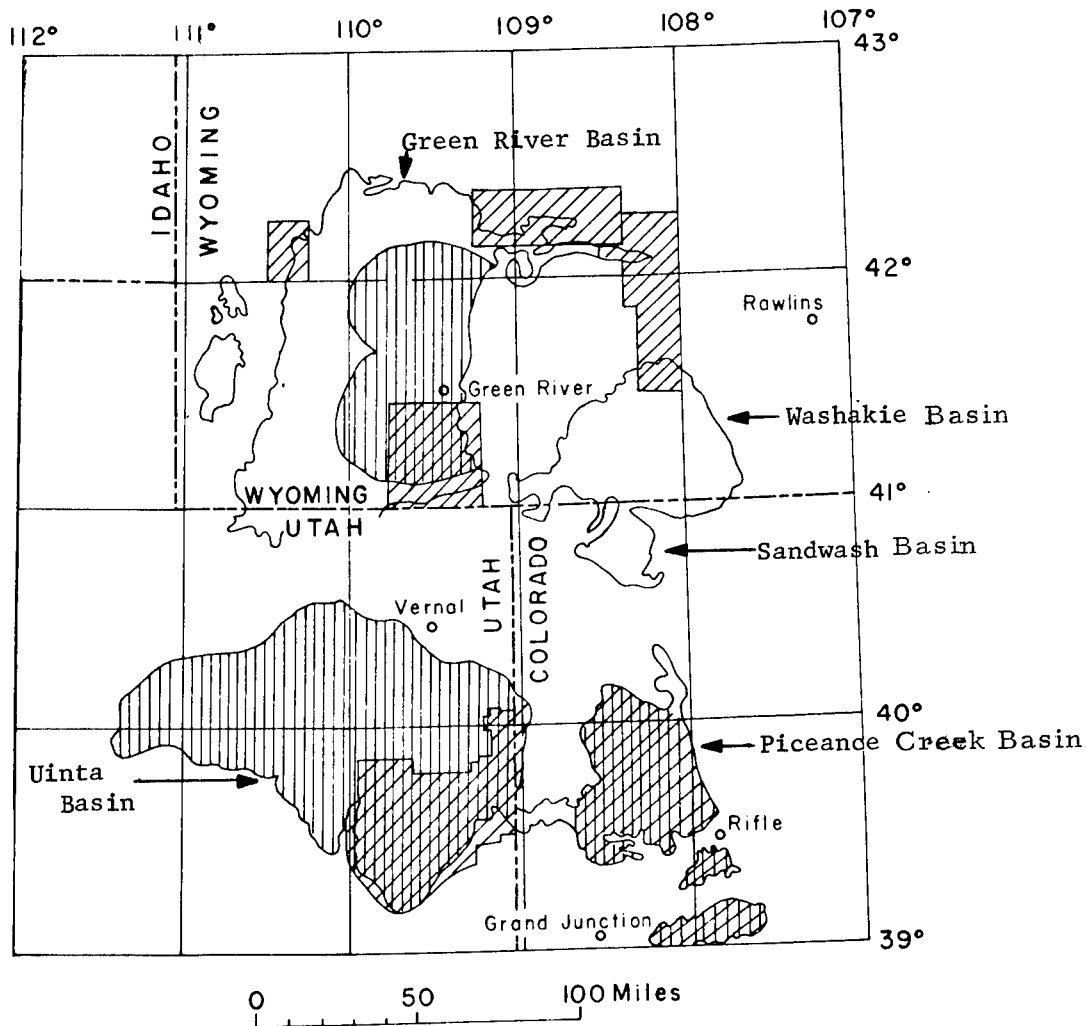
* The term "undiscovered resources" is used in various Department of the Interior publications. These columns refer to resources which are expected to exist but the exact extent of which has not yet been determined.

Figure 2.2--Principal Reported Oil-Shale Deposits of the United States



SOURCE: Duncan, Donald C., and Swanson, Vernon E., "Organic-Rich Shale of the United States and World Land Areas," U. S. Department of the Interior, GSC 523, 1965.

Figure 2.3



Location of areas that have been mapped in detail and in which oil-shale resources have been evaluated. Diagonal ruling indicates areas mapped or being mapped by the U.S. Geological Survey, at scale 1:62,500 or greater. The vertically lined areas indicate oil shale resources which have been partly evaluated and are presently being drilled to determine thickness and quality of the oil shale.

SOURCE: Donnell, John R., "Geology and Oil Shale Resources of the Green River Formation," Quarterly of the Colorado School of Mines, Vol. 59, No. 3, July, 1964.

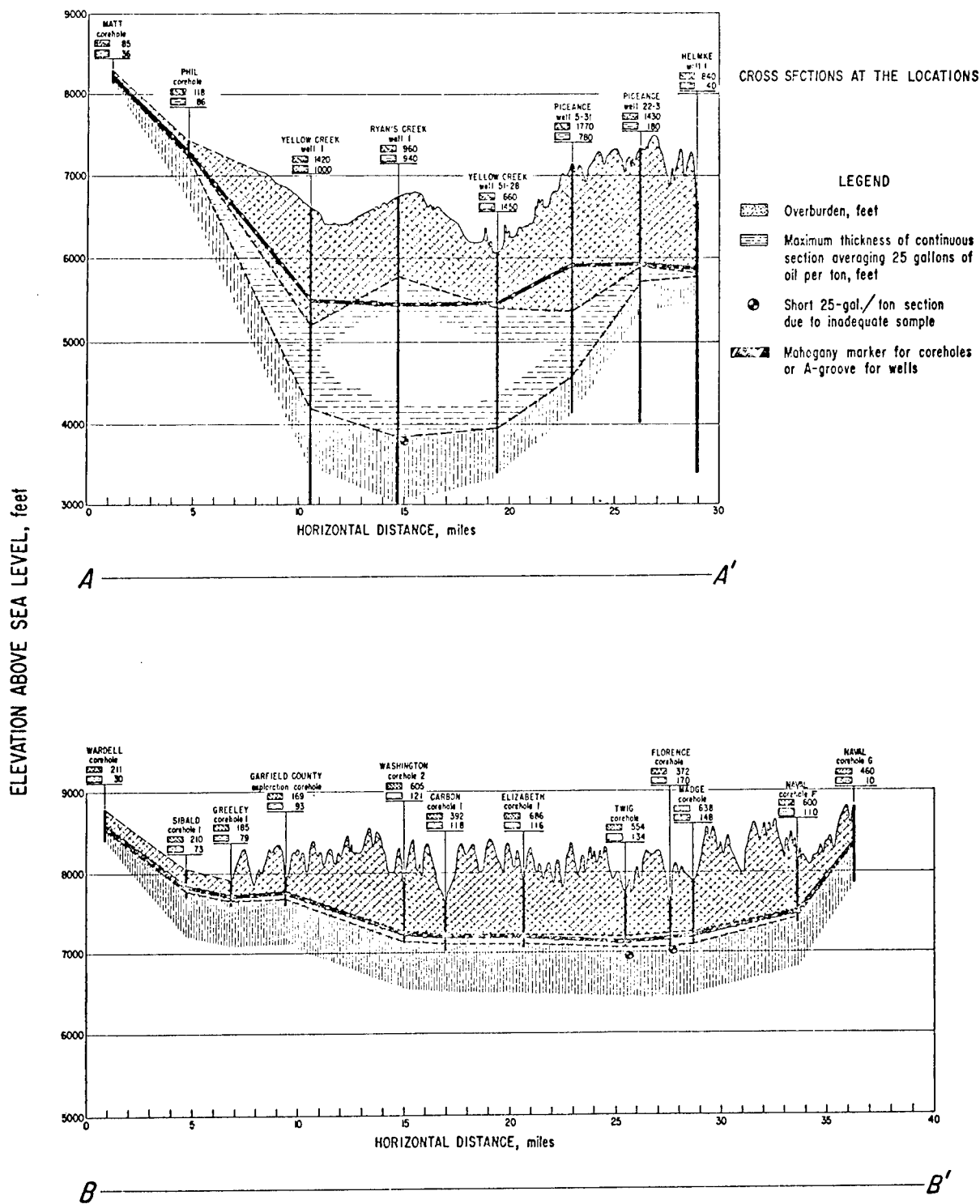
though these are mostly expected to be thin and therefore not suited for the nuclear in situ recovery technique (see microeconomic section).

2.3.1 The Green River Formation

At present the largest potential is that of the Green River formation (Figure 2.3). The thickness of the Piceance Basin is shown in Figures 2.4 and 2.5.

As shown in Figure 2.3, the Green River formation itself is a conglomerate of various basins extending from Northeast Colorado into Utah and Wyoming. The major basins of this formation are the Piceance Creek Basin, the Uinta Basin, the Green River Basin and the Washakie Basin. Other minor basins are grouped around these four major basins (Grand Mesa, Great Divide Basin, Sandwash Basin and others) [30, 91, 113]. These basins extend over an area of 16,900 square miles [30, 113] and reach at certain points a thickness up to and exceeding 2,000 feet in 25 gallons per ton oil shales [91, 113 et al.]. The major part of the Piceance Creek basin reserve is formed by oil shale formations exceeding 100 feet in thickness, and average thickness exceeds 1,000 feet in the major part of the basin [113, et al.] (Figures 2.4 and 2.5). Of the Green River formation, only the Piceance Creek basin has been carefully evaluated while the remaining basins still await more thorough evaluation. The extent to which these basins have been evaluated is shown in Figure 2.3. Table 2.8 was derived from data in [30], one of the most recent studies.

Figure 2.4--Cross Section of Piceance Creek Basin
in North Western Colorado
OIL-SHALE MINING, RIFLE, COLO., 1944-56



SOURCE: East, J. H., and Gardner, E. D., Oil Shale Mining, Rifle, Colorado, 1944-56, U. S. Bureau of Mines, Bulletin 611, Washington, D. C., 1964.

OIL-SHALE RESOURCES OF THE UNITED STATES

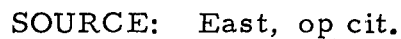


Table 2.8-- Known Oil Shale Deposits of
the Green River Formation (in 10^9 Barrels)

	Grade of Oil Shale		
	25-65	10-25	5-10
Colorado (Piceance)	450-500	800	200
Utah (Uinta)	90	200	1,500
Wyoming (Green River, Washakie)	30	400	300
	≈ 600	1,400	2,000

SOURCE: Duncan, Donald C., and Swanson, Vernon E., "Organic-Rich Shale of the United States and World Land Areas," U. S. Department of the Interior, GSC 523, 1965.

As distinct from the crude oil resources referred to in the previous section, these oil shales are, however, proven reserves of organic material, the location and extent of which is known. The potential extensions and upward revisions of the figures cited for the Green River formation again are estimated to equal the known, measured resources themselves. The major part of these extensions is reasonably expected to lie at some depth in the Uinta Basin alone (i.e., not suitable for open pit mining or similar conventional schemes). Even more vague and due for upward corrections are the resources present in the Green River Basin, Washakie Basin, and the Sandwash Basin, all part of the Green River formation. The possibly richest layers in the Green River Basin have not yet been evaluated [91] (Figure 2.3). The Washakie and Sandwash Basins are not evaluated at all.

Thus, if "crude oil resource estimate standards" are applied, we can say that the Green River formation contains a known resource of about 4000×10^9 barrels of shale oil (as compared to the roughly $30\text{-}50 \times 10^9$ of potential oil in U. S. petroleum reservoirs drilled and an additional 4000×10^9 barrels of shale oil which are expected to be measured mainly in the unexplored Uinta, Green River, and Washakie Basins alone,* which has to be compared with the 1000×10^9 barrels crude oil reserves expected ever to be discovered, of which 400×10^9 barrels may be recoverable. How much of this shale oil can be recovered will depend mainly on the available recovery techniques developed by the time these resources are needed or can become competitive. The Bureau of Mines estimated that by conventional techniques up to 50 per cent ($2,000 \times 10^9$ barrels) would be recoverable [28, 56]. Nuclear in situ techniques have some advantage over conventional techniques and should yield at least 20 per cent to 25 per cent more in total shale oil recovered from the available formation than conventional mining-retorting techniques.

Of interest also is that these oil shale resources are often "associated" (at greater depth) with large, tight gas reserves which were considered in the MATHEMATICA report on gas stimulation [125].

2.3.2 The Devonian and Mississippian Black Shale

The other conglomerate of oil shale reserves lies in the Eastern and Central United States (Devonian and Mississippian Black Shales) [30,

* Includes low grade oil shales.

113, et al.]. The thicker part of these formations and the largest potentials, at least for nuclear techniques, are concentrated in relatively unpopulated areas. Figure 2.6 shows oil and gas bearing areas of the Devonian and Mississippian shales [61]. The potential oil content of these shales was estimated in [30] as 400×10^9 barrels of known reserves in 5-25 gallon grade oil shales and potential extensions of these reserves by another $2,600 \times 10^9$ barrels of shale oil reserves of middle and low grade [30, p. 9 and p. 13-19]. The ultimate potential of these "black shales" was estimated in another reference to lie somewhere between 8 to 24×10^{15} cubic feet of methane energy yield equivalent [31, p. 40-57].

2.3.3 Conclusions

If one applies standards which seem to be accepted in the case of crude oil reserve estimates (see above), then the ultimate resources of shale oil exceed any comparable figure in energy content of other organic matter, with the possible exception of coal deposits. The next table summarizes these estimates for shale oil in the U. S. and is given in Q ($1Q = 10^{18}$ British thermal units).*

Table 2.9 was derived from [30, p. 9 and p. 18]. 2×10^{12} barrels of shale oil (12Q) would cover U. S. oil demand at the present market share and rate of growth (3 per cent in U. S.) for the next 95 to 100 years.

* The conversion factors used in this report are:

Natural Gas	1 cubic foot =	1,000 Btu
Crude Petroleum and Shale Oil	1 barrel =	6,000,000 Btu
Coal	1 short ton =	25,000,000 Btu

This map is preliminary and has not been
edited for conformity with Geological
Survey format and nomenclature

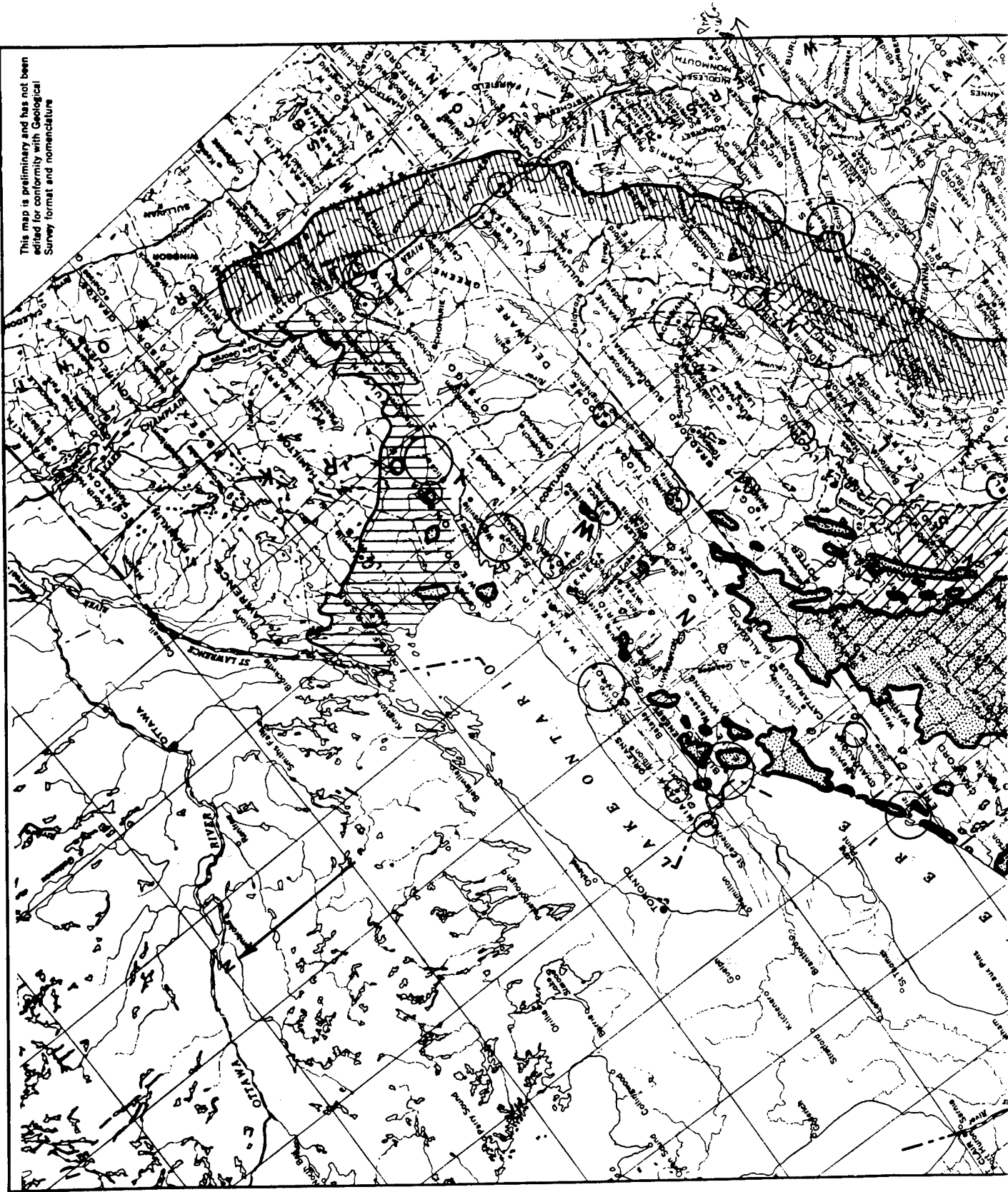
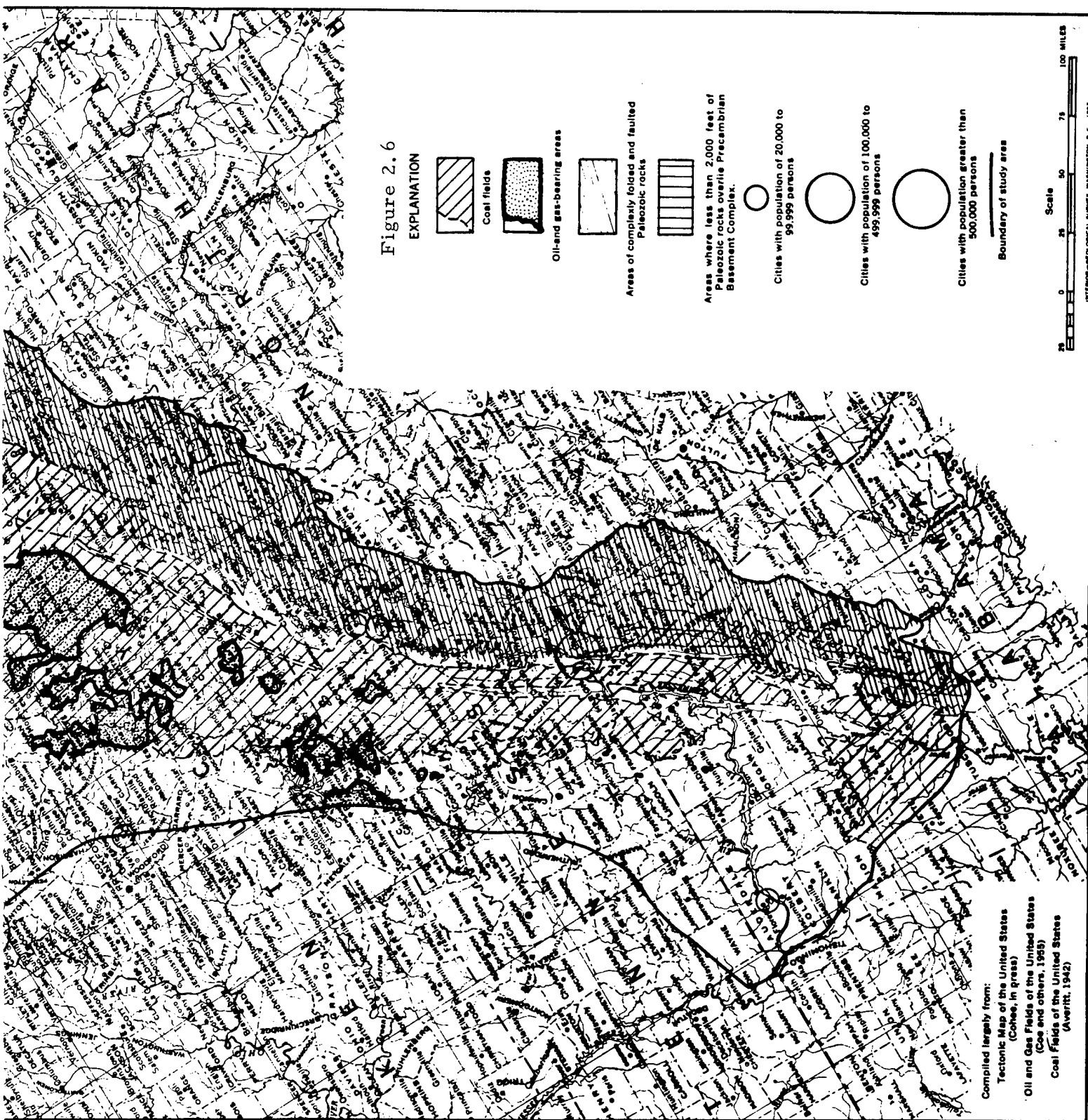




Figure 2.6
EVEN ANIMATION



The more likely 4×10^{12} barrels would be more than sufficient to cover any demand for oil as a supply of energy over the next four to five generations (200 years). During this time other energy supply sources will, hopefully, have been developed. The question of whether in the long run the use of these high grade organic reserves as energy supply is desirable or not is--though serious and important--a problem which does not directly relate to our questions at hand, i.e., how oil shale reserves compare with crude oil reserves and other fossil fuel reserves.

The estimate of 170Q of total potential U. S. resources in 10-100 gallons grade shale which underlie the United States may appear to be extremely high. However, an intensive search for oil shales, comparable to those made for crude oil, has not been made, and these estimates may again prove, as in the history of crude oil reserves, to be conservative. This 170Q resource figure has to be compared with the 84Q of total discovered and expected marginal coal reserves figure published by the Department of the Interior [24, p. 6]. One may object to such a comparison since only a small fraction of these resources might be economically recoverable. But this argument holds equally for coal reserves. Even so, one is still left with about 70Q energy equivalents in known reserves, marginal and submarginal resources in the U. S. (from Table 2.9). Thus, the table published in [24] and which formed the basis to the "Oil Shale Advisory Committee" reports is to some extent misleading as it inadequately reflects the potential oil shale reserves; though in a footnote to

Table 2. 9--Shale Oil Resources of the United States in Q

Deposits	Known Resources			Possible Extensions of these Reserves		Total Reserves Including Unappraised and Undiscovered	
	Recoverable Conventionally	Marginal and Submarginal ***	Potentially Recoverable with Plowshare	10-100	5-10 **	10-100	5-10 **
Green River formation	.5	10-100 11.5 5-10 ** 12.	12.	12.	12.	24.	24.
Devonian and Mississippian	none	1.2	large	4.8	10.8	6.	12.
Marine-Alaska	small	small	some	2.7	large	2.7	large
Associated with Coal*	-	-	n-e	n-e	n-e	1.9	1.3
Other*	-	-	-	-	-	135.0	802.7
Total U. S. Energy Consumption in 1965	.48	12.7	13.2	19.5	22.8	170.	840.

* unappraised or undiscovered

** 10-100 gallons shale oil per ton of oil shale and 5-10 gallons shale oil per ton of oil shale

*** under conventional techniques

SOURCE: Duncan, Donald C., and Swanson, Vernon E., "Organic-Rich Shale of the United States and World Land Areas," U. S. Department of the Interior, GSC 523, 1965.

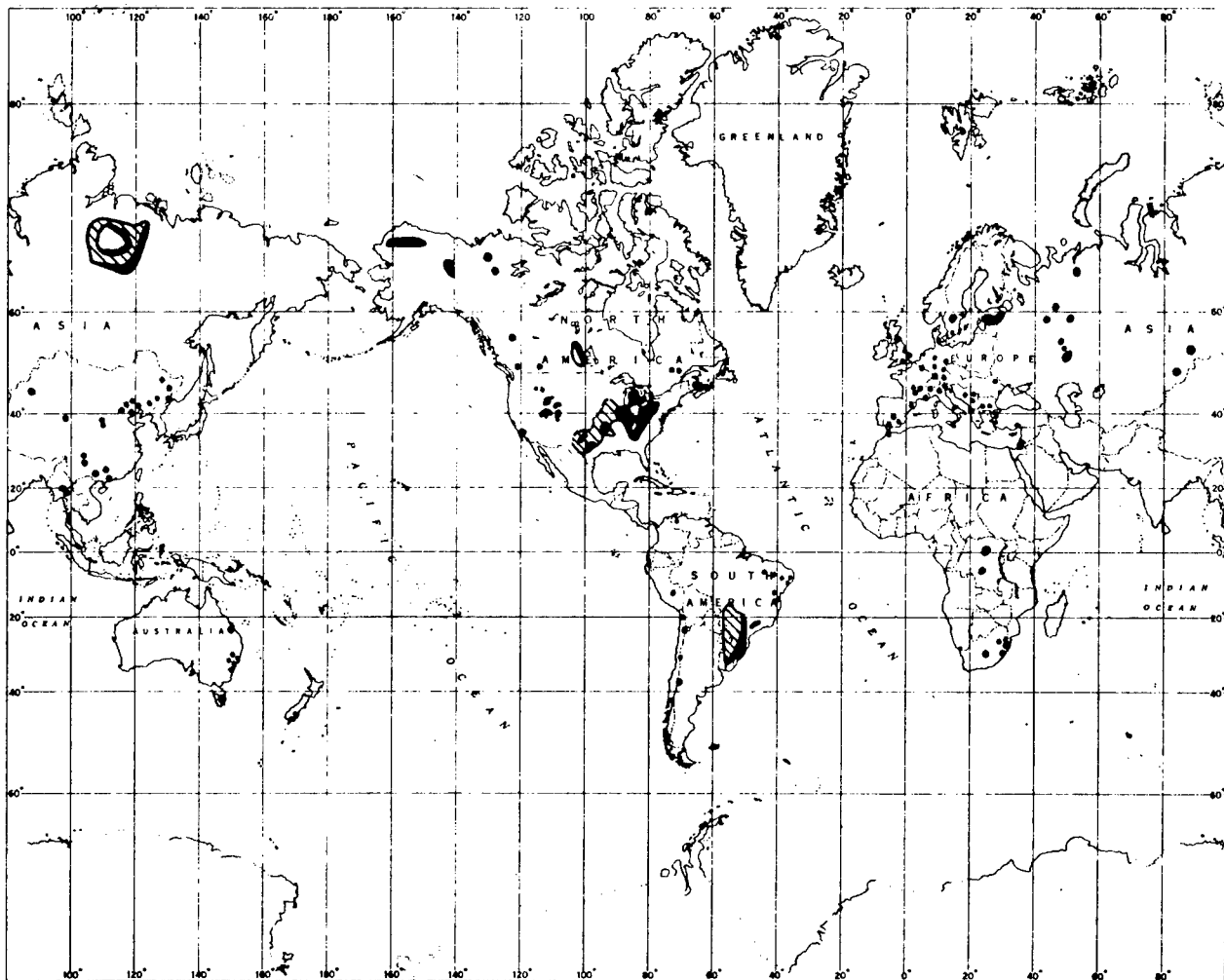
that table on a later page, the 170Q estimate is mentioned (and only refers to 10 gallon grade reserves or better reserves). With these qualifications Table 2.10 shows the relation of U. S. fossil fuel reserves (in Q) [24, p. 6].

The last row in Table 2.10 gives potential oil shale figures; in the "recoverable" columns the assumption was made that nuclear in situ recovery proves to be successful. What the table does reflect accurately is the relative scarcity of crude oil and gas reserves in relation to known and potential reserves in oil shale and coal.

2.4 WORLD RESOURCES IN OIL SHALE

We have noticed the difficulty in determining reserve figures even within very broad bounds for the United States [121, 126 to 130]. To a still greater degree the same difficulty arises when trying to advance estimates on world shale oil reserves and potentials. (See Figure 2.7.) We cannot claim any accuracy in this regard as the exploration of these world resources is just beginning. However, "known resources" and "possible extensions" of Table 2.11 appear to be very conservative, as the example of North America alone shows. It may well turn out that the last two columns of Table 2.11 are in the neighborhood of the true figures [30, p. 18]. There exists some (minor) disagreement between these estimates and those advanced by a recent United Nations study on known recoverable shale oil resources [149]. The estimates of [30] and [149] are compared in Table 2.12 (in Q). In comparing these reserves with the

Figure 2.7--Principal Reported Oil-Shale Deposits of the World



SOURCE: Duncan, Donald C., and Swanson, Vernon E., "Organic-Rich Shale of the United States and World Land Areas," U. S. Department of the Interior, GSC 523, 1965.

Table 2.10-- U. S. Resources of Fossil Fuels
(Energy Equivalents in Q = 10¹⁸ Btu)

	Known Recoverable Resources (= Reserves)	Undiscovered Recoverable Resources*	Known Marginal Resources	Undiscovered Marginal Resources*
Coal	4.6	n-c	29.	55.
Petroleum	.28	1.15	.2	1.7
Natural Gas	.3	1.3	n-c	.9
Natural Gas Liquids	.03	.14	n-c	.3
Oil in Bituminous Rock	.01	n-e	n-e	.1
Shale Oil	.3	n-e	11.6	23.2
Potential Oil Shale figures (if Plowshare successful)	[12.0]	[n-e]	[12.0]	[large]
Total Q	5.5	2.6	41.	81.

U. S. Consumption in 1960 0.06 Q

* See footnote, p. 42.

SOURCE: U. S. Department of the Interior, "The Oil Shale Problem," A synopsis prepared for the opening meeting of the Department of the Interior, Oil Shale Advisory Board, July, 1964.

Table 2.11--Shale Oil Resources of the World Land Areas in Q

Continents	Known Resources		Possible Extensions of Known Resources		Total, including Unappraised and Undiscovered**	
	Recoverable Conventionally	Marginal and Submarginal*	10-100	5-10	10-100	5-10
		10-100				
Africa	.06	.54	n-e	n-e	504	2,700
Asia	.12	.5	n-e	n-e	700	3,500
Australia	small	n-e	n-e	n-e	126	600
Europe	.18	.3	n-e	n-e	165	840
North America	.48	12.7	13.2	20.4	318	1,560
South America	.3	4.5	n-e	20	252	1,260
Total	1.14	18.7	13.2	63.6	≈ 2,000	10,500

* under conventional techniques

** see note to Table 2.10

SOURCE: Derived from: Duncan, Donald C., and Swanson, Vernon E., "Organic-Rich Shale of the United States and World Land Areas," U. S. Department of the Interior, GSC 523, 1965.

Table 2.12--Estimates of Known Recoverable Shale Oil Resources

in Q (>10 gallon grade)

	U. S. Geological Survey	United Nations
U. S.	13.2	6.95
Brazil	4.8	5.05
U. S. S. R.	0.69	0.62
Congo (L)	0.6	0.08
Canada	0.3	0.21
Italy	0.21	0.23
China	0.17	0.16

SOURCES: United Nations Department of Economics and Social Affairs,
 "Progress and Prospects in the Utilization of Oil Shale, Sept., 1965.

Table 2.13-- World Resources of Fossil Fuels
(Energy Equivalents in Q = 10^{18} Btu)

Source	Known Recoverable Reserves	Undiscovered** Marginal Resources
Coal	18	320.
Petroleum	1.7	23.
Natural Gas	2.0	21.
Natural Gas Liquids	.2	3.2
Oil in Bituminous Rock	.2	6.1
Shale Oil	.9	79.
Revised Shale Oil Figures	[12.0]	[170-800]*
Total Q	23.	452.

* potentially for U. S. alone

** see note to Table 2.10

SOURCE: U.S. Dept. of the Interior, "The Oil Shale Problem," Oil Shale Advisory Board, July, 1964. (Chart derived from this.)

rest of the fossil (fuel) reserve base of the world, we again have to revise somewhat the estimates in [24] above with information available on U. S. reserves. The recoverable amounts of shale oil by nuclear in situ techniques would be large. As in the U. S. we find that the large part of organic matter resources of the world are mainly contained in two media, oil shales and coal (see Table 2.13). The scarcity of conventional crude oil and natural gas reserves in relation to available coal and shale oil resources will, at least in the long run, induce some large scale exploitation of shale oil reserves to provide for the increasing demand for oil (7 per cent growth rate on a world-wide level in 1965 above, see Table 2.13).

In countries where crude oil is or was scarce, conventional shale oil operations are employed. How these methods compare with the nuclear in situ techniques is analyzed below in the micro-economic section. Major shale oil operations are carried out or planned in the following countries:

a. China (Manchuria, Kuan-tung), estimated reserves $3 - 6 \times 10^9$ metric tons. China operates the most successful conventional oil shale plant on 15 gallons per ton near Fushun in 180 tons per day retorts. The oil shale is co-mined with deeper coal formations. Exceeds 40,000 barrels per day production. [94, pp. 175ff.]

b. Brazil (Paraiba Valley). Major resources and research program since 1950. A prototype mining and retorting plant is being realized

(PETROSIX). Resources in a country and continent with scarce fossil fuel resources with only a few exceptions (especially scarce are suitable coal deposits); adequate for extremely large industry [93].

c. U. S. S. R. (Estonia, Lower Volga, Siberia). The U. S. S. R. made major efforts in shale oil refining and processing as basis of chemical production. At least one new plant completed after 1950. Large potential resources (See Figure 2.7). The U. S. S. R. also reported progress in developing a solid refractory heat carrier system retort. Work on a 500t per day prototype plant is in progress [149]. The Estonian oil shale plant converts shale oil to gas with Leningrad as the main center of demand. In connection with in situ retorting, another fact is of interest here: a certain percentage of gas is obtained by an underground gasification method by burning poorer grades of coal underground. This is an indication that in situ operations actually work on a large scale (though in a somewhat different field). [95, pp. 56 ff.] The U. S. S. R. has, however, yet to develop fully its vast conventional oil resources and the present contribution of the above processes is negligible.*

d. Congo Republic (Leopoldville). Potentially large high grade oil shale reserves [93].

e. Other oil shale formations and plants are known to exist in France, Germany, New Zealand, Scotland, Italy, South Africa, Spain,

* Shale oil production in 1963 was reported as 18,308 metric tons ($\approx 150,000$ barrels).

Sweden, Thailand--Burma (high grade), Yugoslavia, Australia, Canada, Austria, Peru, Bulgaria [86, 93]. Present world prices are such that a major technological breakthrough is needed to extend these activities beyond their present low levels. The potential reserves are given, but the extent of their utilization will depend to a large degree on expected production costs.

Chapter 3

MICRO-ECONOMIC ASPECTS AFFECTING NUCLEAR IN SITU RETORTING OF OIL SHALE

The facts that no conventional shale oil industry exists in the U. S. and that there has been no experiment in the field of nuclear in situ retorting outline the difficulties and uncertainties encountered when one tries to make any detailed cost-price analysis of these potential industries. In the following pages, information in three areas is collected: (a) crude oil costs and prices, (b) conventional shale oil production and (c) nuclear in situ shale oil production. Any significant development of oil shale industries would affect directly the crude oil industry, an industrial complex with a gross annual product of about 10 billion dollars. Through substitution it would equally affect the natural gas and coal industries, which are of about the same national importance as the crude oil industry itself. Thus, any statement made in this section is bound to be subject to divergent opinions.

Most of the information with regard to crude oil industries originates from industry itself, and this again has certain effects on the quantity and quality of information disclosed as it is not in the particular interest of most firms to release all the information at their disposal.

3.1 COSTS IN THE OIL INDUSTRY

The costs of a barrel of crude oil at the well-head are a somewhat intricate concept. The problem arises from the difficulty of allocating correctly the finding costs of the oil field itself (a main part of the overall costs of the oil industry) to any particular barrel of oil produced. The other main components of crude oil costs are the development costs of the oil field once it is discovered, and the production costs themselves.

Table 3.1 [143, p. 63] was compiled by H. Steele and tries to arrive at some overall crude oil production costs at the well-head.

3.1.1 Finding Costs

Given a yearly production of about 10 per cent of known, measured reserves or about one per cent of total reserves ever to be discovered and produced, and given that cumulative production up to 1966 was about 80×10^9 barrels or 20 per cent of total reserves ever to be produced (260 per cent of known, measured reserves), one expects to find signs of increasing difficulties for discovering, developing, and producing additional crude oil in the U. S. In part, this is reflected in the figures of Table 3.1.

Crude oil reserves are distributed over various formations, with a varying distribution of sizes of reserves and varying degrees of certainty. Any addition to the inventory of existing reserves does involve costs to the firm, whether those additions are made to the stock of inferred reserves or to known, measured reserves by successful wildcat drilling. Even when drilling has proved successful, the potential reserves of that particular

Table 3.1--Trends in Finding, Development, and Production Costs for Crude Oil

Replacement Costs, 1940 - 1960 (Current Dollars)

Year	Finding Costs			Development Costs (Priestman)	Production Costs (Priestman)	Total Costs per Barrel (in royalties)		
	Priestman *	Struth **	Priestman Costs NPC Reserves ***			(1)+(4)+(5)	(2)+(4)+(5)	(3)+(4)+(5)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1940	.11	.12	.12	.32	.33	.75	.76	.77
1941	.17	.13	.19	.27	.37	.81	.77	.83
1942	.19	.13	.30	.21	.36	.77	.70	.87
1943	.23	.15	.25	.29	.35	.87	.79	.89
1944	.13	.16	.25	.28	.42	.83	.86	.94
1945	.29	.21	.33	.34	.43	1.06	.98	1.10
1946	.26	.25	.45	.30	.43	1.00	.99	1.18
1947	.37	.23	.61	.41	.54	1.32	1.18	1.56
1948	.29	.31	.42	.33	.68	1.29	1.32	1.42
1949	.23	.31	.40	.39	.72	1.35	1.42	1.52
1950	.34	.39	.61	.57	.76	1.67	1.72	1.94****
1951	.46	.42	1.02	.37	.80	1.63	1.59	2.18
1952	.60	.58	.92	.64	.83	2.07	2.05	2.38
1953	.49	.76	.87	.61	.89	1.99	2.26	2.36
1954	.54	.71	.97	.83	1.00	2.36	2.53	2.80
1955	.65	.75	1.36	.94	1.01	2.60	2.69	3.30
1956	.62	.78	1.32	.90	1.05	2.58	2.74	3.27
1957	.60	.96	1.40	1.06	1.12	2.79	3.14	3.58
1958	.75	.91	1.71	.89	1.18	2.76	2.98	3.78
1959	.55	.91	1.60	.70	1.15	2.39	2.75	3.39****
1960	.90	-	2.08	.88	1.18	2.96	-	4.15
1964			2.44	1.03	1.38			4.85

*

Journal of Petroleum Technology, November 1960, pp. 11-14.

**

Petroleum Engineer, November 1960, pp. B19-B23.

National Petroleum Council, "Discovered Reserves and Production Capacity," Washington, D. C., 1961.

Rounding off differences, as original figures, were given with three decimals.

SOURCE: Steele, H. B., "The Prospects for the Development of a Shale Oil Industry," Western Economic Journal, Vol. 53, December, 1963.

reservoir can be estimated accurately only after some finite production history of the well.

Any individual firm will have some particular distribution of reservoir sizes and certainty attached to them. If a further expansion of the reserve inventory is called for, the firm may add to its expected reserve potential by acquiring new properties and rights, and it may expand its inventory of known, measured reserves by wildcat drilling. This exploratory drill activity will be determined by the particular reserve situation of the firm, and to some extent also by the prevalent market price for crude oil. The firm may have a long-run exploration plan allocating fixed amounts for drilling activities each year but may still respond to price changes in crude oil by adjusting the expected success ratio of fields drilled. On the other side the firm may decide to concentrate exploratory activities in periods where the financial and general market conditions are most favorable, as exploratory costs are a long-run investment within the firm's activities without affecting the short-run production volume (five to ten years and more).

Each of columns (1), (2), and (3) in Table 3.1 shows a different set of data covering identical exploratory expenditures per year. In 1960 the finding costs differed by more than 100 per cent. It is important here to understand how these figures were arrived at: in each case total exploratory cost per year (mainly drill crew hours worked) was divided by the "gross additions to reserves" of that year, nationwide. The concept of

gross additions to reserves is in itself very vague and can only be evaluated some time after the wildcat drill is successful. Each of the authors (Priestman, Struth, NPC) came to a different evaluation of reserves added, the NPC estimate being consistently the most conservative. This procedure also leads to wild fluctuations in yearly finding cost (± 60 per cent a year), depending on the particular success ratio of that year.

A better procedure would be to allocate yearly exploratory cost to that year's overhead production cost if exploratory activity in the firm is somewhat constant over time.

It would be more accurate to write off the finding cost of crude oil in the next successive years during which these additional reserves are exploited. This implies a certain "smoothing out" of finding costs and would give more accurately total production costs at well-head than those shown in Table 3.1.

The response of exploratory drilling to price increases in crude oil is difficult to determine. Price increases may induce a producer to develop small-sized, but more certain fields.* This would increase the success ratio of wildcat drilling and increase the number of new wildcat fields drilled simultaneously, while the average size of reservoirs would decrease. This would happen at least over the short run so long as the firm has not yet exhausted its inventory of certain, small-sized reservoirs.

* The drilling of verified oil fields is referred to as development drilling. However, wildcat drilling can be made in more or less certain, expected oil fields.

Small-sized reservoirs become attractive only at higher prices. In the long run higher crude oil prices would make attractive both certain, small-sized fields and less certain, large-sized fields, while certain large-sized fields will be developed in any case.

Given the available data in 1964, F. M. Fisher made an empirical study of these correspondences and came to significant though not unexpected results [144], covering the period from 1946 to 1955. Fisher's main results are summarized in equations (1), (2), and (3) [144, pp. 21 ff.]. The number of wildcats drilled at time t in district j ($=W_{jt}$) was related to drilling crew time (in crew years) ($=H$); the price of crude oil ($=P$, in 1947-1949 constant dollars); the average size of oil discoveries per productive wildcat ($=S$); the success ratio ($=F$, ratio of productive wildcats to total number of wildcats drilled), and the average size of associated natural gas discoveries ($=N$, in 10^6 cubic feet) as follows:

$$\begin{aligned} \log W_{jt} = & 8.29^* + 0.00862^* H_{jt} + 2.85^* \log P_{jt} & (1) \\ & (1.54) \quad (0.000724) \quad (0.525) \\ & + 0.440^* \log S_{jt-1} - 0.941^{**} \log F_{jt-1} \\ & \quad (0.0985) \quad (0.304) \\ & - 0.563^* \log N_{jt-1} \\ & \quad (0.119) \end{aligned}$$

$$R^2 = 0.839^* ; \text{degrees of freedom} = 44$$

For the success ratio of wildcat drilling, F. M. Fisher obtained the following relation, where D stands for average depth of wildcats drilled:

$$\begin{aligned} \log F_{jt} = & 1.99^{**} + 0.581^* \log F_{jt-1} - 0.150^* \log S_{jt-1} \quad (2) \\ & (0.651) \qquad \qquad \qquad (0.0407) \\ & + 0.0830 \log N_{jt-1} - 0.000106^{**} D_{jt-1} \\ & (0.0448) \qquad \qquad \qquad (0.000375) \\ & + 0.000590^{***} H_{jt} - 0.356 \log P_{jt} \\ & (0.000283) \qquad \qquad \qquad (0.234) \end{aligned}$$

$$R^2 = 0.729^*, \text{ degrees of freedom} = 43$$

Similarly, the average size of oil discoveries per productive wildcat (S_{jt}) was found to be dependent on other variables and its own past values as shown in equation (3):

$$\begin{aligned} \log S_{jt} = & 5.35^* + 0.777^* \log S_{jt-1} + 0.692^{***} \log F_{jt-1} \quad (3) \\ & (1.73) \qquad (0.113) \qquad \qquad (0.329) \\ & - 0.489^* \log N_{jt-1} - 2.18^{**} \log P_{jt} \\ & (0.137) \qquad \qquad \qquad (0.631) \end{aligned}$$

$$R^2 = 0.848^*, \text{ degrees of freedom} = 40$$

R^2 is the multiple correlation coefficient

<p>* significant at 0.1% level</p> <p>** significant at 1% level</p> <p>*** significant at 5% level (the numbers in parentheses are standard errors)</p>	}	<p>Equations</p> <p>(1), (2), and (3)</p>
--	---	---

If equation (1) is partially differentiated with regard to price, we obtain the respective price elasticities of wildcat drilling to changing crude oil prices. On this data base, the price elasticity is 2.85. Regressions over other data gave F. M. Fisher similar price elasticities of 2.45 and 2.27 [144, pp. 29-39]. This means roughly that a 10 per cent price increase in crude oil would induce a 25 per cent increase in wildcat drilling. On the other side, in the same study F. M. Fisher found that the success ratio had a negative price elasticity ranging from -0.36 to -0.39 (-0.365 from equation (2)) while a partial differentiation of equation (3) shows a similar negative price elasticity of -2.18. Other data gave price elasticities up to -1.63.

Similar relations were observed by F. M. Fisher with regard to associated gas discoveries.

The overall effect of price increases on additions to measured reserves is thus complex. Additions to reserves are here defined as the product of wildcats drilled, the success ratio and the average size of reservoirs discovered.* The overall price elasticity of reserves is then 0.3 only: that is a 10 per cent price increase in crude oil would induce only a 3 per cent increase in reserves. These relations hold at least in the short run, i.e., periods well within the reserve horizon of individual firms.

* Additions to reserves generally also include extensions to known fields and revisions.

From this, some of the faults of calculating finding cost per barrel in Table 3.1 are evident, though in the long run these errors may average out. The overall, low price elasticity of crude oil reserves would be a factor seriously effecting the long term outlook of prices in oil industry. It implies, among others, that present additions to reserves can only be increased by considerably more than proportional price increases in crude oil, a trend which is reflected in the 20 year series of Table 3.1, whichever of the three series we choose.

There are, however, more arguments to support a greater long run price elasticity than the 0.3 elasticity found above. First, we may cite the general tendency of larger price elasticities of long run supply functions as compared with short run functions, due to adaptation lags within firms and the industry as a whole. Thus, in the above estimate, short run effects may have been predominant or short run and long run effects mixed up. Moreover, given the distribution of reservoirs of each firm, price increases in crude oil induce a particular increase in the exploration of small-sized reservoirs (price elasticity of -2.18 in equation (3)). This overemphasis on the development of small-sized fields may well be a short run development on the basis of accumulated knowledge on these fields in earlier times when prevailing prices did encourage any venture into such fields. After this set of fields is developed, firms may extend their exploratory activity along previous lines, increasing thereby the average size of fields discovered.

Institutional factors help also to explain a tendency toward the exploration of small-sized, high cost reservoirs with increasing crude prices, as Steele showed in [143]. They are mainly:

a. An encouragement of overdrilling given fields, due to the "rule of capture," which results in considerable technological diseconomies.

b. A preferential treatment of higher cost wells, due to limits imposed on allowable production per well per month in order to maintain prices. While highly productive wells were idle up to 260 days a year in 1962 [143, p. 69], marginal (stripper^{*}) wells were mostly exempt from productive restrictions. Such regulations induce a development of costly, i. e., small-sized reservoirs with increasing prices. This is again reflected in the rising cost figures of Table 3.1.

After an additional 20 to 30 years of continued expansion of crude oil production, other "inelasticities" will exert themselves. In a 20-year period more than twice the amount of crude oil will have been produced than presently known reserves (80×10^9 against 30×10^9 barrels). Based on the very general assumption that, in secular economic developments, best fields are developed and produced first, two factors will

* Wells drilled in addition to existing wells and diverting oil from other wells in such a way as to affect negatively the overall economics of the oilfield as a whole. The definition for "stripper" wells accepted by the Stripper Well Committee is any well that produces less than an average of 10 barrels daily over a period of a year.

simultaneously tend to increase crude oil costs. First, a rising difficulty of finding additional crude oil fields even with advanced, costly detection methods; and second, mining development and production costs due to deeper and harder overburden and lower permeability. This leads to the other main components of real crude oil costs: development cost (20 per cent) and production cost (30 per cent) (Table 3.1).

3.1.2 Development and Production Costs

During the 1940-1960 period, development costs rose by about 20 per cent (in 1958 dollars) and production costs by another 56 per cent (in 1958 dollars), while finding costs increased by 340 per cent to 725 per cent (depending on source) for the same period. [143]

As with finding costs, so also in the case of these costs several qualifications have to be made. Development and production costs of Table 3.1 represent national averages, that is, marginal wells and highly productive wells are all mixed together. Furthermore we already mentioned the general trend toward the development of marginal wells, the restriction imposed on submarginal wells and the bias toward overdrilling of fields. All these are factors which, if removed, would considerably lower real costs of a major part of the U. S. oil industry. With regard to drilling costs again, F. M. Fisher estimated in 1964 the drilling cost function in crude oil industry and shifts that occurred from 1955 to 1959. F. M. Fisher found equation (4) to correspond most closely to the available data: [144]

$$Y = K (e^{\alpha X} - 1) \quad (4)$$

Where

Y = Costs per well in \$

X = Depth in feet

α = Parameter expressing "curvature" of cost function

$K = H/\alpha$

H = Limit of marginal costs as X approaches 0.

For both productive and dry wells, F. M. Fisher shows some decrease in the overall cost function at drilling depths of 5,000 feet and 10,000 feet and inconclusive results for drilling costs down to 15,000 feet. A similar decrease is at least partially reflected (on a much more aggregate basis) by the Priestman figures of Table 3.1. The summary of Fisher's results is given in Tables 3.2 and 3.3. Tables 3.2 and 3.3 analyze the drilling costs of available well data and parameters of the cost function (equation (4)) subdividing changes in cost into definite decreases, probable decreases, no significant changes, probably increases and definite increases. Each category contains the number of regions and the number of wells within that range. Both tables summarize changes in K , α , H , MC , and Y . Changes in K , α , and H are given for the overall cost function (equation (4)), while changes in MC and Y are classified for different depths. Overall, we may say that during these years drilling costs remained stationary.

Table 3.2--Changes in the Drilling Cost Function 1955/6 - 1959
as Established by F. M. Fisher

DRY WELLS

	Definite Decrease r ; w	Probable Decrease r ; w	Insignificant or no change r ; w	Probable Increase r ; w	Definite Increase r ; w
K_1/K_0	11 ; 11542	2 ; 542	2 ; 2245	2 ; 1385	9 ; 3256
	10 ; 4093	2 ; 684	1 ; 1937	4 ; 3787	9 ; 8479
H_1/H_0	14 ; 12655	1 ; 1937	0	3 ; 1817	8 ; 2566
MC_1/MC_0 5,000 feet	17 ; 13209	2 ; 2438	3 ; 906	0	4 ; 2422
10,000 feet	13 ; 5461	3 ; 3548	1 ; 1937	3 ; 2116	6 ; 5913
15,000 feet	11 ; 4211	0	2 ; 3684	7 ; 5158	6 ; 5922
Y_1/Y_0 5,000 feet	15 ; 14423	0	3 ; 1003	1 ; 158	7 ; 3391
10,000 feet	16 ; 8251	2 ; 4490	5 ; 4372	1 ; 308	2 ; 1554
15,000 feet	13 ; 5461	3 ; 3548	1 ; 1937	3 ; 2107	6 ; 5922
TOTAL 26 regions, 18,975 wells					

r = number of regions in that category

w = number of wells in that category

Subscript 0 indicates 1955/6.

Subscript 1 indicates 1959.

SOURCE: Fisher, F. M., Supply and Costs in the U.S. Petroleum Industry, Baltimore, 1964.

Table 3.3--Changes in the Drilling Cost Function 1955/6 - 1959
as Established by F. M. Fisher

PRODUCTIVE WELLS

	Definite Decrease r ; w	Probable Decrease r ; w	Insigificant or no change r ; w	Probable Increase r ; w	Definite Increase r ; w
K_1/K_0	9 ; 10392	1 ; 3175	2 ; 798	6 ; 5863	8 ; 10120
	9 ; 10443	2 ; 3996	2 ; 726	4 ; 2064	9 ; 13119
H_1/H_0	9 ; 9623	1 ; 3175	3 ; 5014	3 ; 1820	10 ; 10716
MC_1/MC_0					
5, 000 feet	11 ; 11377	2 ; 2238	0	2 ; 1341	11 ; 15392
10, 000 feet	7 ; 8085	5 ; 5552	0	4 ; 1778	10 ; 14933
15, 000 feet	7 ; 8085	3 ; 4291	1 ; 448	5 ; 3841	10 ; 13683
Y_1/Y_0					
5, 000 feet	13 ; 16209	1 ; 2053	2 ; 4193	1 ; 323	9 ; 7570
10, 000 feet	10 ; 10408	4 ; 3711	1 ; 1093	1 ; 1018	10 ; 14118
15, 000 feet	7 ; 8085	4 ; 4739	1 ; 813	4 ; 1778	10 ; 14933
TOTAL	26 regions, 30,348 wells				

r = number of regions per category

w = number of wells per category

Subscript 0 indicates 1955/6.

Subscript 1 indicates 1959.

SOURCE: Fisher, op cit.

The rising trends in finding costs and the less pronounced trends in development and production costs of crude oil are in part reflected in the development of the average crude oil price which increased threefold since 1940 but has remained stationary since about 1958. Table 3.4 shows the development of crude oil prices since 1918 [148, p. 102].

If these prices are deflated, they imply certain decreases of crude oil prices over the last decade. We, furthermore, note that whatever the methods are of measuring crude oil costs at well-head, they exceed in recent years the average crude oil price at the well-head. To some extent this is due to the dubious character in which finding costs are treated as shown in Table 3.1.

Moreover, there are several indications that the real production costs for a substantial part of U. S. crude oil industry are lower. In support of this we note that, up to 1962, of the 30,000 oil fields discovered, only 241 fields provided 57.4 per cent of U. S. production [143], even under the institutional restrictions mentioned.

Also, in the short run and over medium time periods, the oil industry could continue its operations at considerably lower prices, ultimately at direct production costs only (\$1.20 - \$1.40 U. S. average).

In our comparative analysis of crude oil and shale oil costs, we will ignore the strong trends of cost increases of major components of crude oil costs, mainly finding costs, and assume that the \$2.90 price per barrel of crude oil will suffice to cover all crude oil costs over the

Table 3.4-- Crude Oil Price Changes since 1918
at Well-head, Current Dollars/Barrel

Year	Price	Year	Price	Year	Price
1918	1.98	1934	1.00	1950	2.53
1919	2.01	1935	.97	1951	2.53
1920	3.07	1936	1.09	1952	2.68
1921	1.73	1937	1.18	1953	2.78
1922	1.61	1938	1.13	1954	2.77
1923	1.34	1939	1.02	1955	2.79
1924	1.43	1940	1.02	1956	3.09
1925	1.68	1941	1.14	1957	3.01
1926	1.88	1942	1.19	1958	2.90
1927	1.30	1943	1.20	1959	2.88
1928	1.17	1944	1.21	1960	2.89
1929	1.27	1945	1.22	1961	2.90
1930	1.19	1946	1.41	1962	2.89
1931	.65	1947	1.93	1963	2.88
1932	.87	1948	2.60	1964	2.88
1933	.67	1949	2.54	1965	2.88
				1966	2.88

SOURCE: World Oil, February, 1966.

next decades of increased oil and demand in the U. S. Such a \$2.90 cost price is conservative and may well be unrealistic in the long run, that is, for periods over 10 years of additional crude oil production.

As a second point of reference, we will compare expected shale oil costs to a lower, minimum cost barrier of \$1.25. Such a cost price would correspond to average U. S. crude oil production costs alone in 1960 or to some local minimum cost figures advanced in different publications on local crude oil costs at refinery, i. e., \$1.75 in the Los Angeles area (\$1.75-\$0.50 transportation costs from Colorado area to Los Angeles), or also to the minimum shale oil costs so far advanced for conventional shale oil production.

Thus, considerable incentives to develop shale oil would exist if technological advances were made which would bring its production costs in the neighborhood of \$1.25 or below. Shale oil costs between \$1.25 and \$1.75 would still leave some room for shale oil development. Costs in excess of these figures would assign to shale oil development only a relatively long run reserve position for the case of substantial crude oil shortages, with substantial price increases.

3.2 CONVENTIONAL SHALE OIL PRODUCTION COSTS

Different types of retorting processes were listed in Section 1. We are concerned here with techniques which in the best of all cases have reached a pilot plant stage. Given the wide potential effects of major breakthroughs and the expectations each firm has regarding its activity in

oil shale research, it is nearly impossible to arrive, at present, at any reliable cost estimates of conventional shale oil recovery methods. In interviews at the joint venture of six oil companies at Rifle, Colorado, at the Bureau of Mines in Laramie, Wyoming, and others, hardly any data beyond the 1950 and 1951 cost estimates of the Bureau of Mines and of the National Petroleum Council (NPC) were made available [113, 138, 139, 140]. There do exist various claims regarding major breakthroughs, e.g., Oil Shale Company's TOSCO - process, but detailed cost figures and an evaluation of scale-up-problems are not available. The most detailed, recent estimate of shale oil costs was made by H. Steele in [143]. These are somewhere in the neighborhood of expected shale oil costs in various projects still being carried on (R. H. Cramer, personal communication). Changes in some of the components of mining costs have occurred since then, but technological cost savings were, in part at least, wiped out by inflationary cost increases. The figures published by H. Steele in 1963 [143, p. 72] are shown in Table 3.5.

Sixty per cent of shale oil costs are evidently caused by mining operations alone (\$1.00 per barrel). Thus, any process which can avoid mining operations (e.g., all in situ processes) could potentially lead to considerable cost savings. These would exclude above ground shale preparation, which causes, according to Steele's figures, 8 per cent of total shale oil costs. (Shale preparation mainly involves the crushing of the oil shale particles to uniform particle size (one inch at Rifle pilot plant). Advances in mining techniques could lead to cost

Table 3.5--Cost Summary for Production of Crude Shale Oil, 1962
(25,000-Barrel-Per-Day Integrated Operation)

	Mining ^b	Shale Preparation	Retorting ^c	Visbreaking	Transportation to Four-Corners Area	Total
	(1)	(2)	(3)	(4)	(5)	(6)
Capital costs: (thousand dollars)						
Direct production facilities	\$ 9,010	\$ 2,756	\$ 9,801	\$ 4,045	\$15,525	\$41,137
Allocated overhead ^d	2,756	954	2,940	1,742	1,380	9,772
Start-up expenses ^e	845	70	198	89	230	436
Working capital requirement ^f	2,798	269	807	353	707	4,934
Total	\$15,409	\$ 4,053	\$13,746	\$ 6,229	\$17,842	\$57,279
Operating costs: (dollars)						
Costs per calendar day						
Depreciation ^h	\$ 2,954	\$ 518	\$ 1,756	\$ 794	\$ 2,326	\$ 8,348
Operating costs	22,126 ^g	1,871	5,476 ^g	2,439	3,967	35,879
Total	\$25,080	\$ 2,389	\$ 7,232	\$ 3,233	\$ 6,293	\$44,227
Less by-product "credits" ^a	579	145	497	228	621	2,070
Total	\$24,501	\$ 2,244	\$ 6,735	\$ 3,005	\$ 5,672	\$42,157
Costs per barrel of shale oil (cents)						
Depreciation ^h	11.8¢	2.1¢	7.0¢	3.2¢	9.3¢	33.4¢
Operating costs	88.5	7.5	21.9	9.7	15.8	143.4
Total	100.3¢	9.6¢	28.9¢	12.9¢	25.1¢	176.8¢
Less by-product "credits" ^a	2.3	.6	2.0	.9	2.4	8.2
Total	98.0¢	9.0¢	26.9¢	12.0¢	22.7¢	168.6¢

∞
O

Table 3.5 (continued)

- a For by-product retort gas sold locally. Process credits allocated arbitrarily on basis of relative capital investments.
- b 30-gallons-per-ton oil shale, mined by room-and-pillar method from sites on cliff face.
- c Retorted by Bureau of Mines gas combustion method, as modified by Cameron and Jones, with twelve cylindrical retorts, 36 feet in diameter, operating at a rate of 300 pounds per hour per square foot of cross sectional area of these retorts.
- d Overhead allocated among processes on various bases to reflect the extent to which such processes benefited from common facilities.
- e Start-up expenses include interest on capital during construction period, costs of personnel training, and costs of initially retarded operating rate.
- f Includes inventories of work in process and of maintenance and operating supplies, funds for contingencies, and reserves for fluctuations, and average accounts-receivable balances.
- g Mining operations charged for retort gas "sold" to the mine by the retort; retorting operations credited with the gas "revenue" as a reduction in operating costs.
- h Mining depreciation includes depletion on land, installations, excavation, and start-up expense. Straight-line depreciation taken on the basis of a 15-year life for mining and shale preparation and 20 years for other facilities.

SOURCE: Steele, H. B., "The Prospects for the Development of a Shale Oil Industry," Western Economic Journal, Volume 53, December, 1963.

reductions in mining-retorting processes. Another feature of conventional shale oil processes is the relatively high proportion of direct costs versus fixed costs. Operating costs (\$1.43) account for more than 80 per cent of total shale oil costs. This limits the short run price range at which any such enterprise could respond to outside price pressures.

More recently, two \$1.25 ultimate cost estimates were advanced. The first was made in reference to the TOSCO process which is being developed by the Colony Development Company, (owned by S. O. of Ohio, (40 per cent), Cleveland Cliffs Iron (30 per cent) and the Oil Shale Corporation (30 per cent)*).

The \$1.25 cost price apparently referred to a 50,000 barrels a day plant and included mining, rock handling, upgrading, and depreciation. Such a cost price would equal production costs of crude oil alone (about \$1.20, Table 3.1), not including finding and development costs [147]. However, the figures for the TOSCO process were obtained from experimental operations. In scaling up these operations to 450,000 barrels a day plant, major difficulties were recently encountered which may affect the economics of this process quite seriously if no additional technological advances are made.

The recent estimate of H. Steele [145] is within the same range of \$1.25 costs for a mining-retorting oil shale plant of 25,000 barrels

* Changes in the Colony Management may have occurred in the meantime.

a day shale oil production. It reflects some technological progress in mining and in retorting over the past two years.

Table 3.6

	<u>H. Steele 1963</u>	<u>H. Steele 1965</u>
Mining	\$ 1.003	\$.832
Shale Preparation	.096	.090
Retorting	.289	.212
Viscosity Break	<u>.129</u>	<u>.120</u>
	\$ 1.517	\$ 1.254

SOURCES: Steele, H. B., "The Prospects for the Development of a Shale Oil Industry," Western Economic Journal, Vol. 53, Dec., 1963.

Oil Statistics Bulletin and Canadian Oil Reports, "Shale Oil... On the Threshold?" Oil Statistics Company, Babson Park, Mass., 1966.

For our comparative analysis we assume these last two estimates to be correct, i.e., that nuclear in situ techniques will only be developed if it leads to cost reductions below these figures. However, favorably as these figures may compare with those of conventional crude oil production, we have to emphasize various factors which adequately explain why no large size conventional shale oil operations have yet been undertaken:

a. All cost figures on shale oil production so far published are extrapolations from experimental results or pilot plants. Any large (25,000-50,000 barrels a day) enterprise would initially be faced with technological and economic scale-up problems (e.g., TOSCO process).

b. Some (external) diseconomies are not reflected in these conventional shale oil estimates. Among them are waste disposal problems

of the spent oil shale (gray-black in color and oily smell), water requirements and labor shortages.

c. On a firm basis these operations may be profitable, but even in 70-100 feet, horizontal oil shale formations over 25 per cent of the shale remains underground in form of pillars. In thick oil shale formations (Piceance Basin over 2,000 feet) only a small fraction of total oil shale present could be mined, thereby resulting in the loss of a large portion of high grade oil shales which remain underground in the form of pillars, foundations, and roofs. Some oil shale beds are fractured extensively and would make any mining operation expensive if not impossible. Nevertheless, even in the relatively compact formations mined up to now, various roof falls did occur [113] increasing the hazards and costs of the industrial safety program.

d. Although at \$1.25 cost per barrel of shale oil ultimately a large-scale program might be started, the crude oil figures in Table 3.1 (finding cost \$2.44, development cost \$1.00 and production cost of \$1.40 in 1962) do not reflect potential short run and long run costs of major crude oil producing centers.

However, as oil shale deposits are known and no finding costs have to be included, in the long run a \$1.25 per barrel cost could, nevertheless, be very attractive. The oil industry itself may be expected to generate a major initiative in oil shale only after a substantial depletion of their present crude oil reserves in which they have made major investments. As compared with the nuclear in situ technique, the conventional mining-

retorting techniques will rather be a welcome complement than compete with the nuclear technique directly. From the following analysis it is evident that nuclear in situ techniques will pay off only in oil shale beds of 100 feet or more in thickness; on the other side, mining techniques so far developed are limited to a maximum height of 70 feet to 100 feet. In thicker formations more mines would have to be developed vertically, i. e., leaving a substantial amount of oil shale underground as roof and foundations. Thus, conventional and nuclear in situ techniques do not directly compete with each other.

3.3 COSTS OF THE NUCLEAR IN SITU RETORTING PROCESS

It is difficult to give any detailed appraisal of the economics of a technique that has not yet been applied in a single test or prototype operation. Depending on various sources the answers will differ. Yet, there exists general agreement that this technique has enough of an economic potential to warrant testing, and the major part of U. S. oil industry has now joined efforts for such a test, though many of the participating companies did spend a considerable amount of research of their own mostly in different "conventional" oil shale techniques.

The economics of the nuclear in situ retorting technique will roughly depend on the following parameters:

- a. The percentage of shale oil recovered by the in situ retorting technique from the rubble chimney;

b. The extent of the rubble chimney in oil shale formations (and its particle size distribution);

c. The extent of control over the burning front in fragmented oil shale, which determines retort size and compressor requirements;

d. The amount of shale oil recovered from the fractured zone around the chimney;

e. Extent of radioactive contamination of shale oil;

f. The thickness of the oil shale formation;

g. The grade of the oil shale.

The minimum thickness and minimum grade of the oil shale formations where the nuclear in situ technique will be applicable is again a function of the parameters under a, b, c, d, and e. The only detailed study of the expected costs of a nuclear in situ shale oil plant was made by M. A. Lekas. There are many open questions as to the accuracy of the assumptions made by Lekas in [117]. Arguments can be advanced which may undermine the economics of this method, making Lekas' figures unrealistic, but there do exist expectations that go beyond the estimates used by Lekas, e.g., on the percentage of shale oil recovered, the average grade of oil shales, the thickness of formations, heat requirements, retort times, etc., which ultimately should lead to cost figures below those proposed by Lekas. The following analyzes the cost figures advanced by Lekas, roughly estimates (log linear) cost functions and then advances various more conservative estimates as to the actual recovery rates, the grade of the oil shales

and their effect on the economics of the nuclear in situ method. The basic assumptions of Lekas' [Figures 3.1, 3.2, 3.4, and 3.5] study are:

- a. An area of 25-50 acres per retort, i.e., a maximum controllable burning front of 50 acres.
- b. Four to 20 retorts which are combined to one plant such that production of the plant extends up to 10 years.
- c. A daily production of 75,000 barrels in 25 gallon grade oil shale, and 45,000 barrels in 15 gallon grade oil shale (i.e., constant speed to burn within retorts).
- d. No significant contamination hazards.
- e. Recovery rates of 75 per cent of the shale oil in place.
- f. Present knowledge of the techniques of underground nuclear explosions.
- g. Advance of burning front by one to two feet per day (similar rates were achieved in the Laramie retort).

In the plant layout shown in Figure 1.3, the plant would extend over an area of 250 acres and comprise four retorts of 25 acres each (100 acres, or 40 per cent of total area). In his analysis, Lekas assumes that oil would be recovered from the partially fractured walls between the chimneys. Depending on the grade of the oil shale (15-25 gallons), the thickness of the shale and the areal extent of the retort, the shale oil produced at a 75 per cent recovery rate would vary between 150 and 260×10^6 barrels shale oil per plant. The main investment cost of such a plant would at present charges

Figure 3.1

Total Plant Investment Costs of 75,000
Barrels/Day Nuclear In Situ Retorting Plant

75% Recovery Rate

25 Gallon Grade Oil Shale

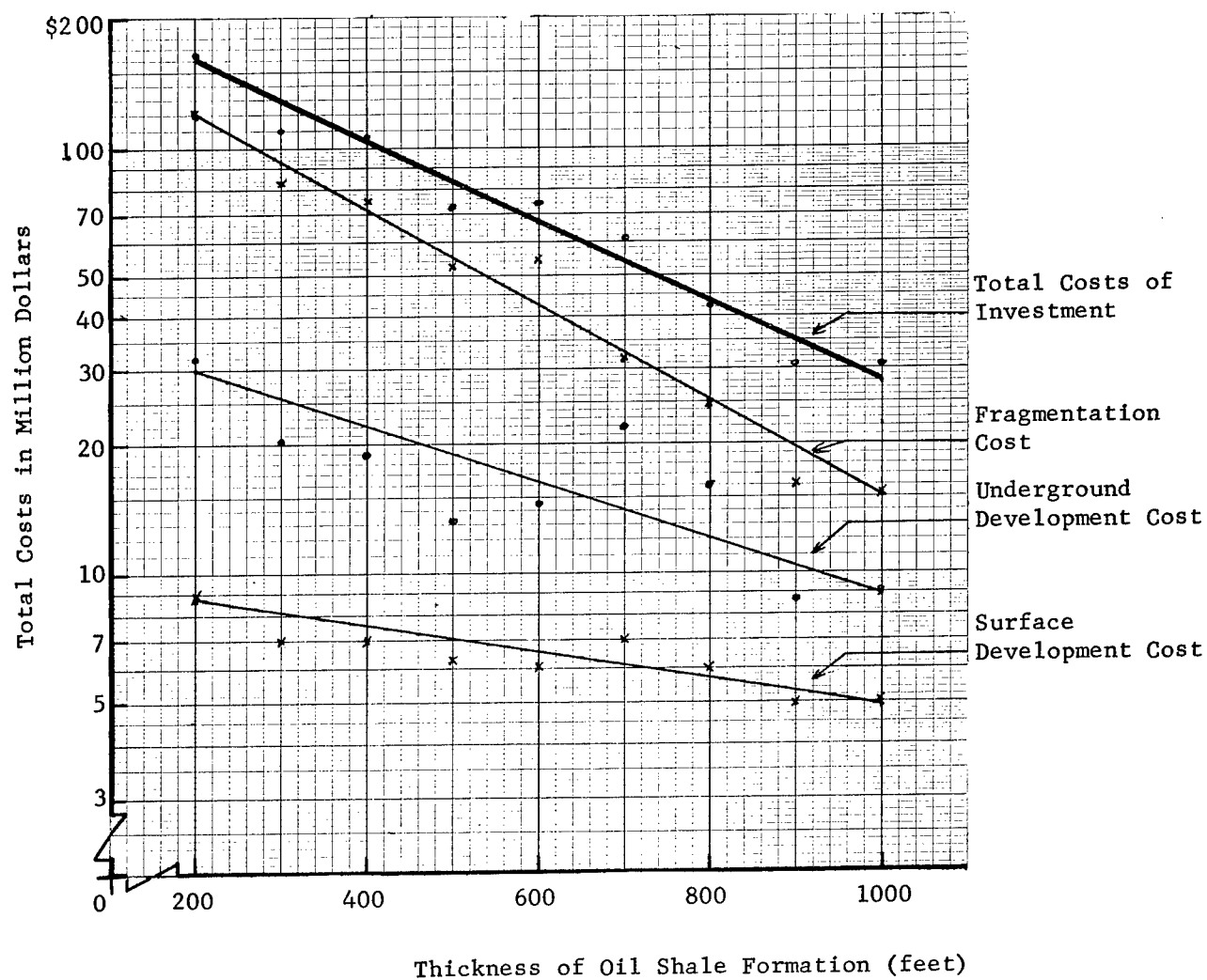


Figure 3.2

COSTS PER BARREL OF SHALE OIL IN 75,000 BARRELS/DAY NO

Capital Cost Per Barrel

75,000 Barrels/Day Production

75% Recovery Rate

25 Gallon/Ton Oil Shale

Cost/
Bbl.

\$1.00

.70

.50

.40

.30

.20

.10

.05

.03

.02

.01

.005

.002

.001

.0005

.0002

.0001

.00005

.00002

.00001

.000005

.000002

.000001

.0000005

.0000002

.0000001

.00000005

.00000002

.00000001

Total Capital Cost
Per Barrel

Fragmenting Cost

Underground
Development
Cost

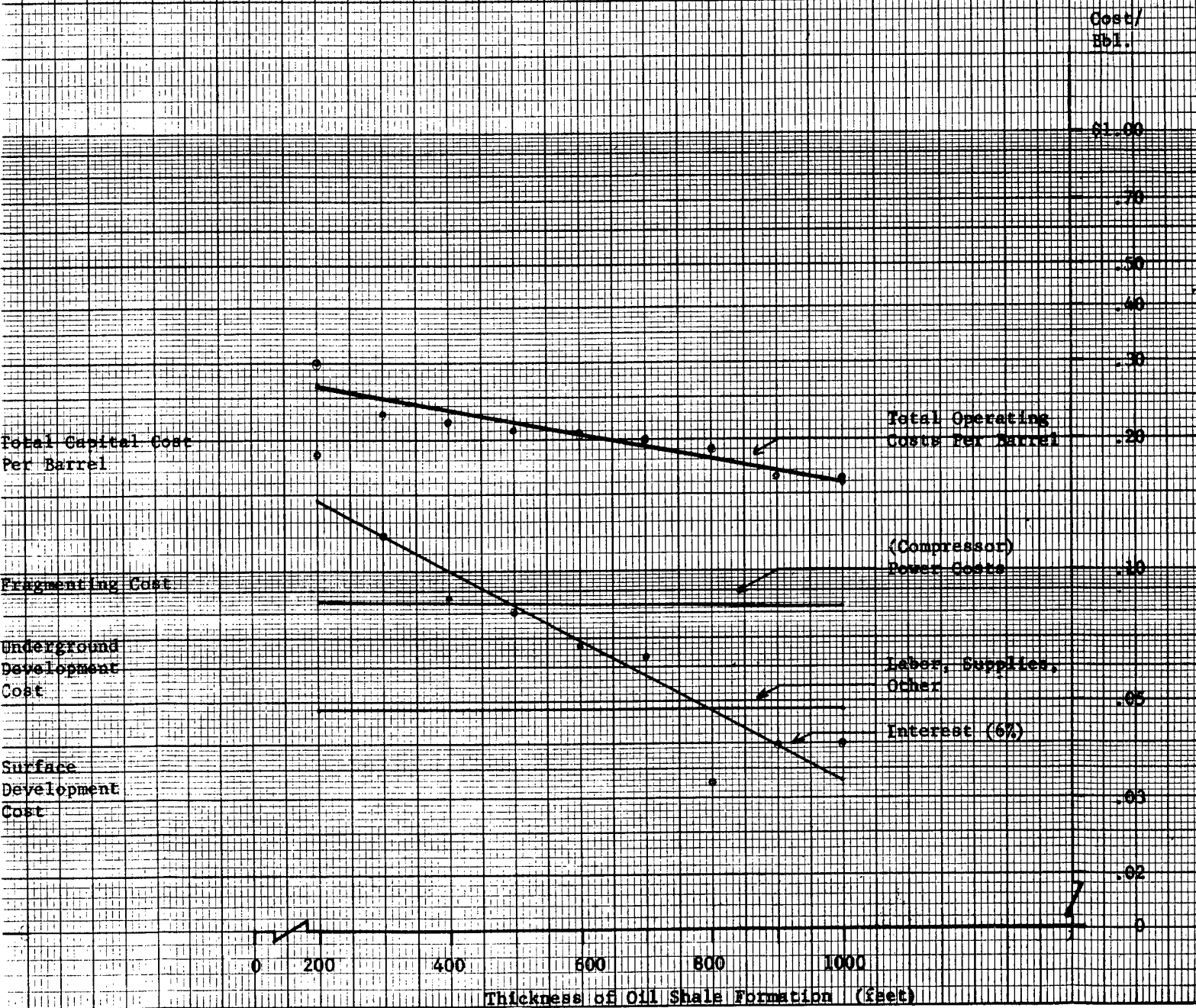
Surface
Development
Cost

Thickness of Oil Shale Formation (Feet)

Figure 3.2

Oil in 75,000 Barrels/Day Nuclear In-Situ Plant

Operating Costs Per Barrel
75,000 Barrels a Day Production
75% Recovery Rate
25 Gallon/Ton Oil Shale



be the nuclear fragmentation cost of the oil shale, about 50 per cent of total costs per barrel at lower yield, 25 per cent of total cost per barrel at higher yields of the nuclear device. Any reduction in this cost would significantly improve the economics of shale oil production. A 50 per cent reduction in the cost of fracturing the chimney would represent a cost saving of up to 25 per cent in the final production cost of shale oil by nuclear explosives (see Figures 2.7 and 3.1). The fragmentation cost is in part due to the cost of the device itself, and in part due to the cost of the emplacement hole for the device. Lekas' analysis is based on the presently published charges for nuclear excavation explosives by the A. E. C. They are approximately [45, p. 7]

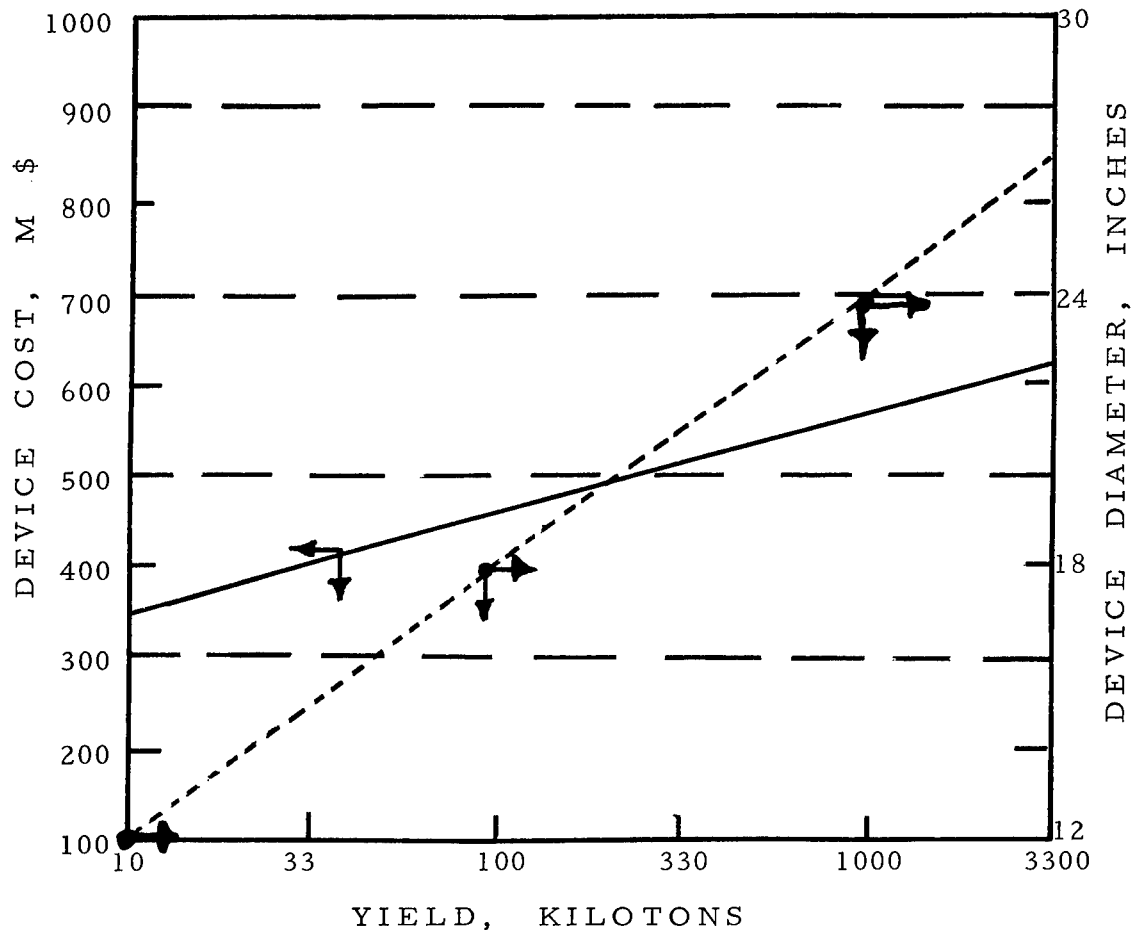
10 KT	\$ 350,000
20 KT	\$ 385,000
50 KT	\$ 425,000
100 KT	\$ 460,000
500 KT	\$ 535,000
1,000 KT	\$ 570,000
2,000 KT	\$ 600,000

The cost of emplacement is a function of both the depth of emplacement and the required diameter of the hole. The diameter of the emplacement hole again is a function of the yield of the device. Figure 3.3 shows the costs of nuclear devices and the approximate diameters as a function of the yield of the device. Technologically no problem exists at depths of emplacement for oil shale fragmentation in the Piceance Basin.

Due to work done at the Nevada Test Site in underground nuclear explosion experiments, considerable technical progress has been achieved in large diameter drill holes. Technically it is feasible today to drill emplacement holes of more than 100 inches in diameter. Relatively shallow holes of up to 180 inches in diameter have been drilled for the emplacement of underground missiles, and in 1962 a 130-inch hole was drilled to a depth of 570 feet and 90 inches in diameter to a depth of 1400 feet [57, pp. 15-16]. Thus, technical limitations due to inadequate drilling capabilities do not exist for anticipated emplacement depths, as the diameters shown in Figure 3.3 are all considerably below proven maximum achievable drill diameters. The equipment and techniques of drilling large diameter holes vary with depth of emplacement and hardness of the rock. In a very general way, drilling costs depend on the time required to drill the hole, which again depends on the drilling penetration rates. Other costs of emplacement are caused by the mobilization and demobilization of the drill equipment, and, in single emplacement projects, also transportation cost. One has also to consider site preparation cost, rig-up and tear-down costs, surface or conductor casing, circulating media costs (fluid or air), drill bit costs, cementing and casing costs [57, pp. 137 ff.]. Many cost items may be substantially reduced in large scale, repetitive applications. In case the nuclear in situ technique is developed by experiments, a situation similar to the Nevada Test Site combined with large-sized oil fields will develop. This means that in a

Figure 3.3

"PRESENT COST OF NUCLEAR EXPLOSIVE
AND DIAMETER OF THE EXPLOSIVE"



Diameters of Nuclear Explosives:

10 KT	>	12 inches
100 KT	>	18 inches
1,000 KT	> >	24 inches
10,000 KT	> > >	36 inches (not shown)

SOURCE: Personal communication by D. C. Duncan, October, 1966.

Lekas, M. A., "Economics of Producing Shale Oil--the Nuclear In Situ Retorting Method," Quarterly of the Colorado School of Mines, Vol. 61, No. 3, July, 1966.

relatively small region, all the technical equipment and personnel is available for repetitive use which entails considerable economies of scale. It is for this environment that M. A. Lekas' figures were estimated. For single experiments the costs are, of course, considerably higher. In its "Oil Shale Feasibility Study" CER-Geonuclear gave a breakdown of figures for a 50 KT nuclear in situ experiment in oil shale at a depth of 3,000 feet, which would also include any attempt to recover shale oil from the surrounding fractured zone of the nuclear chimney. The estimates are given in Appendix I. Ultimately, further research and development on the reduction of the diameter of nuclear devices may lead to such progress that for major applications conventional drill equipment of oil companies may suffice for emplacement hole drilling.

Other investment costs arise from above ground and underground development costs once the retorts are fractured. For the underground development, production wells have to be drilled and gas input holes and gas exhaust wells, an underground collection system, etc. Above ground development costs are mainly due to compressors for adequate air or gas input to heat the oil shale rubble. Additional costs arise from the above ground air and gas distribution pipelines and oil collection facilities. Other costs may arise from decontamination procedures. If this, or a similar experiment in oil shale proves to be successful in the sense that a large amount of the oil shale is fractured and the in situ retort gives a reasonable recovery rate, then a full industrial development of oil

shales by the nuclear in situ method is very likely to be realized. Along with the assumptions made by Lekas this would then lead to potential shale oil prices far below the crude oil costs discussed previously. With a 75 per cent recovery rate from the fragmented oil shale rubble in 25 gallon grade shale, Lekas came, based on the assumptions cited previously, to the following configuration of costs in shale beds of varying thickness: (Tables 3.7 and 3.8) [117, p. 110].

The direct operating costs are minor in relation to the capital costs. The main item is the cost of power for compressors. The labor costs due to plant operation are small and arise mainly from the regulation and supervision of production. This may ultimately affect the overall feasibility of other conventional mining-retorting methods due to the increasing burden on water requirements which would arise in those conventional developments. (Tables 3.9 and 3.10) [117, p. 111]. However, major uncertainties do exist as to the technical requirements of compressors and costs associated with them. The serious influence compressor costs could have on overall shale oil production costs is analyzed below (see Figures 3.7 and 3.8).

The interest charges on capital invested are not operating costs in the strict sense. The total direct costs per day are about \$10,000 per plant. At a daily production rate of 75,000 barrels this would amount to about 14 cents direct cost per barrel of shale oil produced, i.e., about the same as production cost of crude oil in the best fields of the Near East.

Table 3.7--Estimated Nuclear Shale Oil Plant Parameters

Shale bed thickness feet	Explosive yield, kilotons	No. of retorts per plant	No. of explosives per retort	Total No. of explosives per plant	Fragmented shale, millions of tons	Total recoverable		Plant life years ²
						25 gal shale ¹	bbls, millions 15 gal shale ¹	
200	50	20	13	260	386	173	104	6
300	50	12	13	156	348	157	94	6
400	50	12	13	156	468	211	126	8
500	50	8	13	104	386	173	104	6
600	70	8	13	104	572	257	154	9
700	120	12	5	60	496	223	134	8
800	200	8	5	40	536	241	145	9
900	300	4	5	20	346	155	94	6
1,000	500	4	5	20	475	214	128	8

¹ 75% recovery

² Production rate: 25 gallon shale = 75,000 bbls/day; 15 gallon shale = 45,000 bbls/day

SOURCE: Lekas, M. A., "Economics of Producing Shale Oil--the Nuclear In Situ Retorting Method," Third Symposium on Oil Shale, Quarterly of the Colorado School of Mines, Vol. 61, No. 3, July, 1966.

Table 3.8--Estimated Capital Costs for Nuclear Shale Oil Plant

Shale bed thickness, feet	Rock breaking millions \$	Underground development millions \$	Surface installations, millions \$	Total capital investment, millions \$	25 gal shale capital cost per bbl; \$	15 gal shale capital cost per bbl; \$
200	120.8	31.8	8.9	161.5	0.92	1.52
300	74.1	19.1	6.9	100.1	0.62	1.04
400	72.4	19.1	6.9	98.4	0.46	0.76
500	49.2	12.4	5.9	67.8	0.38	0.63
600	41.6	26.6	7.9	76.1	0.38	0.64
700	33.7	21.6	6.9	62.2	0.27	0.45
800	24.3	15.3	5.9	45.4	0.18	0.30
900	15.2	8.2	4.9	28.3	0.17	0.28
1,000	15.5	8.7	4.9	29.1	0.13	0.21

SOURCE: Lekas, op cit.

Table 3.9

Shale Bed thickness, feet	Cost Per Day				Cost per bbl	
	Interest charge, dollars	Labor supplies taxes, misc., dollars	Power, dollars	Total operating charge dollars	25 gal shale, dollars	15 gal shale, dollars
200	13,300	3,700	6,200	23,200	0.31	0.52
300	8,400	3,700	6,200	18,200	0.24	0.41
400	8,200	3,700	6,200	18,000	0.24	0.40
500	5,700	3,700	6,200	15,500	0.21	0.34
600	6,400	3,700	6,200	16,200	0.22	0.36
700	5,300	3,700	6,200	15,000	0.20	0.33
800	3,800	3,700	6,200	13,500	0.18	0.30
900	2,500	3,700	6,200	12,200	0.16	0.27
1,000	2,500	3,700	6,200	12,200	0.16	0.27

SOURCE: Lekas, op cit.

Table 3.10--Summary of Estimated Oil Shale Production Costs

Shale bed thickness, feet	25 Gallon Shale			15 Gallon Shale		
	Capital cost \$ per bbl	Operating cost \$ per bbl	Total cost \$ per bbl	Capital cost \$ per bbl	Operating cost \$ per bbl	Total cost \$ per bbl
200	0.92	0.31	1.23	1.52	0.52	2.04
300	0.62	0.24	0.86	1.04	0.41	1.45
400	0.46	0.24	0.70	0.76	0.40	1.16
500	0.38	0.21	0.59	0.63	0.34	0.97
600	0.30	0.21	0.51	0.47	0.35	0.82
700	0.27	0.20	0.47	0.45	0.33	0.78
800	0.18	0.18	0.36	0.30	0.30	0.60
900	0.17	0.16	0.33	0.28	0.27	0.55
1,000	0.13	0.16	0.29	0.21	0.27	0.48

SOURCE: Lekas, op cit.

The costs calculated by Lekas show considerable discontinuities at certain levels of thickness of the oil shale formation [117]. This is mainly due to a discontinuity in yields of nuclear devices applied in fragmenting oil shale, mainly the change observed in 600 to 700 feet thickness (change from 70 to 120 KT yields, from 8 retorts to 12 retorts per plant, and from 13 nuclear devices per retort to 5 devices per retort). There exists no inherent reason for this discontinuity, and other development schemes with more or less continuously decreasing costs are feasible. A certain degree of irregularity will always persist due to the discrete nature of any change in explosive yields combined in one retort.

Based on Lekas' data, we estimated log-linear cost functions relating the production costs per barrel to the thickness of the formation. Whether such a linear relationship holds or not can not be determined before some empirical data are available. At a first approximation they are a valid interpretation of Lekas' analysis (Figures 7, 8, 9, and 10 in [117]). Figure 3.1 shows total investment costs as a decreasing function of the thickness of the oil shale formation as fewer and fewer retorts can be combined in plants of equal capacity (75,000 barrels a day) with higher yield explosives. The weight of the fragmentation cost is evident. This is still true if the capital costs are related to barrels produced (Figure 3.2). Power cost and labor cost are assumed to be constant per day, which results in constant costs per barrel of shale oil produced as long as the capacity of the plants is held constant at 75,000 barrels a day. Figure 3.2

shows these operating costs and interest charges of 6 per cent on capital invested. Some changes in the technical parameters of Lekas' oil shale plant would affect favorably the economics of shale oil production. There exists no reason why the plant capacity should be held constant at 75,000 barrels a day (or 45,000 barrels per day in 15 gallon oil shales). If in thicker formations an equal amount of retorts with identical areal extent and identical daily burning rates (2 feet) would be combined to our plant, the fragmented shale per plant would be increased considerably, extending the plant life and lowering the capital cost per barrel of shale oil produced beyond the savings already inherent in Lekas' figures. If retorting times are reduced as envisioned in [115] by about 50 per cent due to advanced retorting below the actual burning front, the daily capacity could be doubled at more or less identical development costs, i.e., reducing overall costs by 30 per cent or more. Additional production of shale oil may be derived from the fractured regions around the retorts (50 per cent to 60 per cent of the total plant area) during the retorting of the chimney, and later on by secondary recovery in those areas which may in part use existing plant facilities (mainly wells drilled, the collection system and the compressors). These possible wind fall profits are **not** reflected in the present analysis and no figures can be attached to any of these items as too little is known on the actual retort techniques themselves.

By varying now the recovery rate below the 75 per cent figure assumed, we see that a large "safety" margin is available if the in situ

process should work at all within limits now mentioned (see Figure 3.5). At a 75 per cent recovery rate shale oil can be produced economically below a \$1.25 cost estimate even at an oil shale thickness of about 100 feet. This would comprise all formations in excess of present mining operations at Rifle (70 feet, possibly 100 feet). A 30 per cent, 40 per cent, 50 per cent recovery rate of shale oil would allow the operation to break even with a \$1.25 cost price in formations of about 650 feet, 550 feet, and 350 feet respectively. The higher the recovery rate, the lower is the required thickness of oil shales to make the nuclear process economic. The much higher crude oil price of \$2.90 would allow the nuclear process to "break even" at recovery rates as low as 30 per cent and in formations of only 200 feet (see again Figure 3.5). Given that the main part of the Piceance Basin exceeds 1,000 feet in thickness, (up to 2,000 feet and more of 25 gallon shale) the recovery rate of 75 per cent is not essential to an economic plant operation even if we assume a \$1.25 cost price as an upper limit. The crude oil industry today operates at a recovery rate of about 35 per cent and including secondary recovery, 50 per cent at best. Present experience at the Laramie retort indicates that higher recovery rates, even in excess of 75 per cent, are feasible in oil shale. Equally, the nuclear in situ technique would allow one to exploit oil shale formations below the 15 gallon grade requirement generally advanced at this time. If we assume again that Leka's parameters are accurate, including 75 per cent recovery rate, we may vary the grade of the shale, assuming all other factors as given in [117]. Cost savings by

different plant designing in lower grade shales may be feasible, but are not considered here. In addition, Lekas' 15 grade shale oil cost figures fit the 15 gallon grade cost function extremely well based on an extension of the 25 gallon data above (Figure 3.4). Thus, formations down to 5 gallon grade could be recovered economically at a \$1.25 cost in formations exceeding 1,000 feet in thickness, other parameters being equal. Oil shale of less than 15 gallon grade is not likely to burn. However, as pointed out earlier, such oil shales might be retorted by the hot gas method. For this process, again, the cost figures cited in the previous tables and figures do not apply except for nuclear fragmenting costs. Similar break even points are given for 10 and 15 gallon shale at 650 feet and 400 feet respectively.

A major uncertainty in the costs of the nuclear in situ shale oil production are compressor requirements, compressor investment cost, and compressor operating cost. The air or gas inflow determine the rate at which the oil shale is retorted. The required pressures and rates have not yet been determined at which enough energy is delivered to retort successfully the rubble chimneys. The air or gas rate and the necessary pressures will differ from chimney to chimney, mainly as a function of the water content of the oil shales. A difference in air and gas requirements in such processes causes a substantial difference in compressor investment cost and operating cost, at present, the most variable cost item in the estimates on in situ retorting. Appendix II shows air compres-

Figure 3.4

Costs Per Barrel Shale Oil as a
Function of Oil Shale Grade

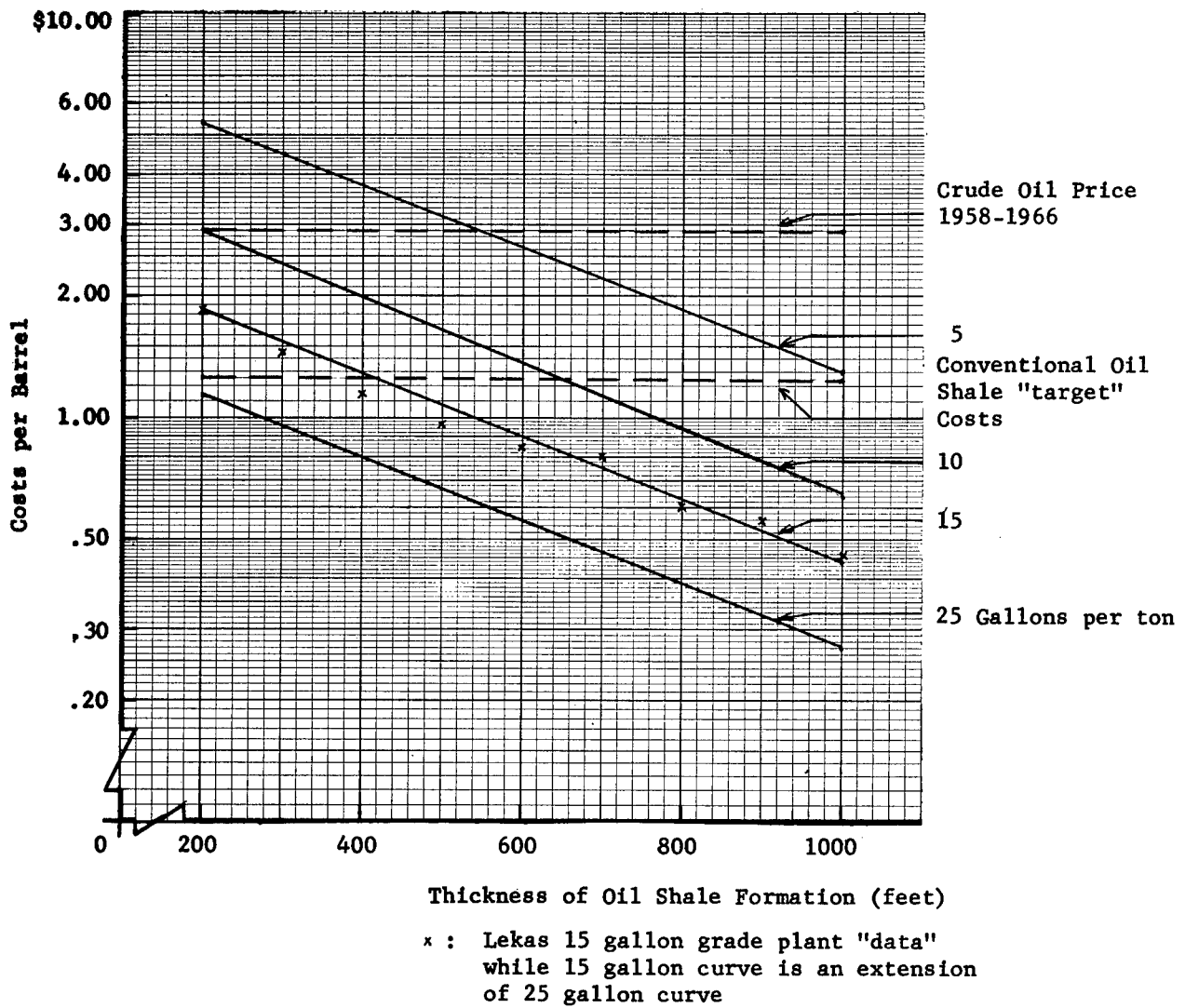
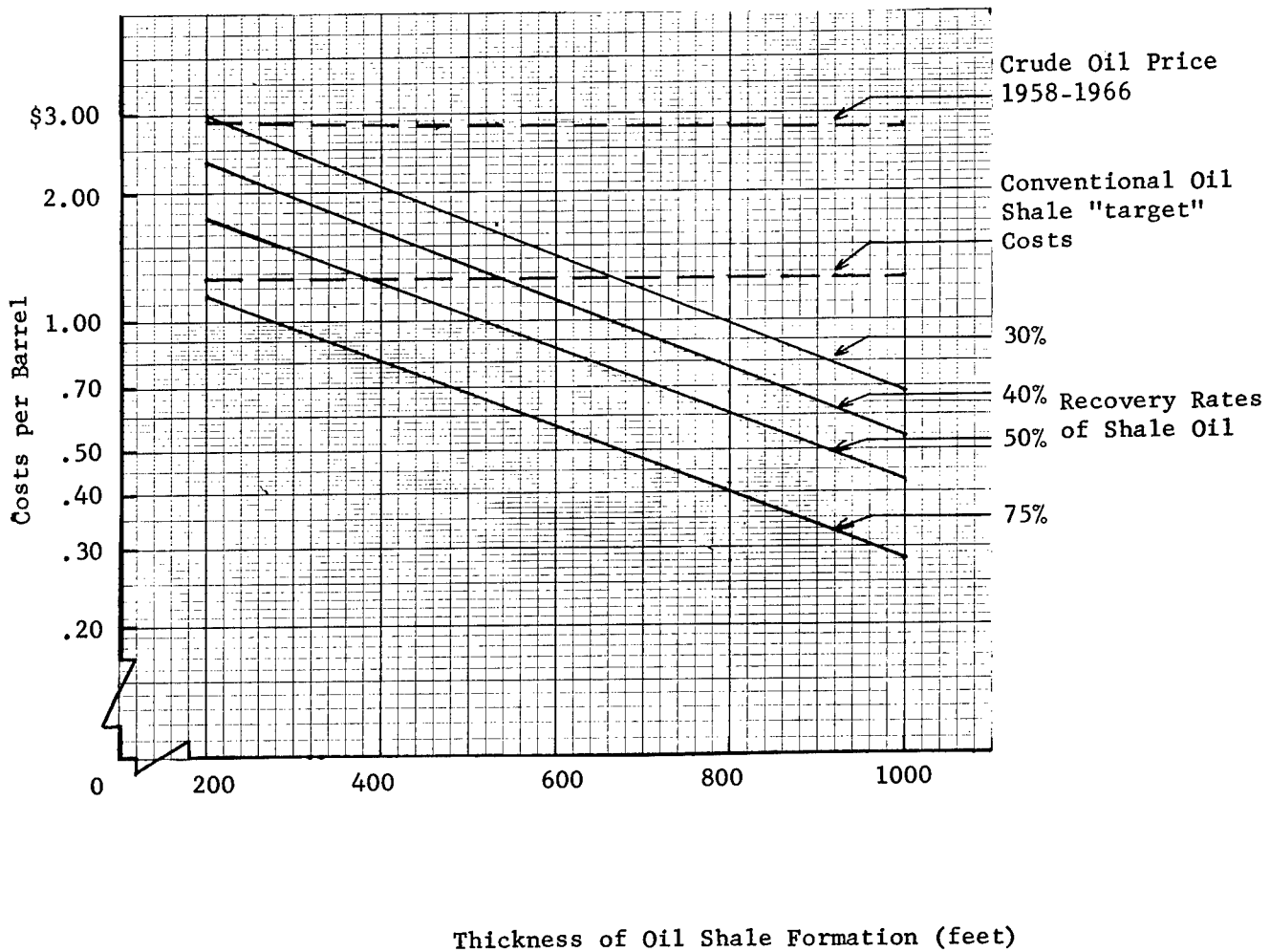


Figure 3.5

Costs Per Barrel Shale Oil as a
Function of the In Situ Recovery Rate



sor requirements for a single 200 KT chimney at 3,000 feet depth. Cases II and IV are based on a preliminary draft on such a retort process [242].

While Lekas' shale oil costs were arrived at assuming a 3,000 scf (standard cubic feet) air requirement per ton oil shale rubble and a 5 psig pressure in the chimney, Cases II, III, and IV assume different technical parameters. They are:

Case I: Assumes technical requirements in air compressors as stated by Lekas, that is a 3,000 scf air per ton of chimney rubble, a pressure requirement of 50 psig, a recovery rate of 75 per cent, a C-value of 325 in the Boardman equation, multiple shots of 200 KT adequate for a ten-year plant life.

Case II: Assumes air requirements of 7,100 scf, operating pressure of 50 psig, a 70 per cent recovery rate, a C-value of 325, a single 200 KT shot, and a one- to two-year plant operation.

Case III: Assumes 7,100 scf in air requirements, an operating pressure of 1,000 psig, a 50 per cent recovery rate, a C-value of 325, a single 200 KT shot, and plant life of one to two years.

Case IV: Assumes 7,100 scf in air requirements, an operating pressure of 1,000 psig, a 50 per cent recovery rate, a C-value of only 275, a single 200 KT shot, and a one- to two-year plant life.

The difference in the C-value and the cost increase induced thereby is shown in the difference between the costs of Cases III and IV. The

linear dimensions of the nuclear chimney as predicted in Case IV are about 40 per cent lower than those assumed in all previous cases.

In line with these and the other differences stated, we observe that air compressor investment costs would rise from the original 5-6 cents in Case I to 8 cents, 18 cents, and 34 cents per barrel of shale oil respectively in the best possible operations (see Figure 3.7).

A similar increase is observed in air compressor operating costs which from the original 8.5 cents rise to 22 cents, 76 cents, and \$1.25 in Cases II, III, and IV. Thus, the overall increase in compressor costs per barrel of oil shale in a single 200 KT chimney would be from expected minimum costs of about 13 cents (Case I, Lekas) or 30 cents (Case II) to 94 cents in Case III and \$1.59 in Case IV, making the in situ retorting process uneconomic in the latter case. It is important, however, to remind ourselves that the Lekas estimate was made for a multiple detonation, large-scale project with a planned life of nearly ten years while Cases II, III, and IV are only single 200 KT detonations with a respective plant life of two years only. Thus, the cost increases in Figures 3.6 and 3.7 may be on the higher side and may not be so drastic in large-scale projects. However, basically compressor requirements are proportional to the rubble mass and should, therefore, not show considerable economies of scale.

Figure 3.6 shows air compressor operating costs in the four cases and their influence on total operating costs as presented earlier; Figure

3.7 shows air compressor investment costs under the four sets of assumptions, total air compressor costs, and their influence on total production costs per barrel of shale oil. As shown in Figure 3.6, the air compressor operating costs in Case IV exceed by themselves the "target" price for conventional shale oil production, assumed to be the competitive limit of either conventional or nuclear shale oil production. Thus, if the technical requirements of Case IV hold, then the nuclear in situ production of shale oil would be uneconomic under present market conditions.

The air compressor operating costs in Case III still exceed the cost estimates of Lekas for total in situ shale oil production costs over a wide range. If to air compressor operating costs the investment costs are added, then the total shale oil production cost in Case III would in general exceed the \$1.25 limit price for the in situ method. But while total costs in Case IV are unacceptably high, Case III would be at least marginally competitive, especially in the thicker oil shale formations where conventional recovery methods are known to be relatively inefficient. On the other side, the cost differences of Cases I and II are negligible if compared to the other two cases. Thus, we may tentatively conclude that among the most crucial parameters in the economics of in situ shale oil production using nuclear explosives are the pressure requirements within the chimney in order to retort effectively the shale oil. Though, under favorable other assumptions, 1,000 psig air pressure requirements would by themselves make this process at best only marginally competitive or a slight change in

Figure 3.6

Total Operating Costs per Barrel
As a Function of Air Compressor (=AC)
Operating Costs
(four cases, see text)

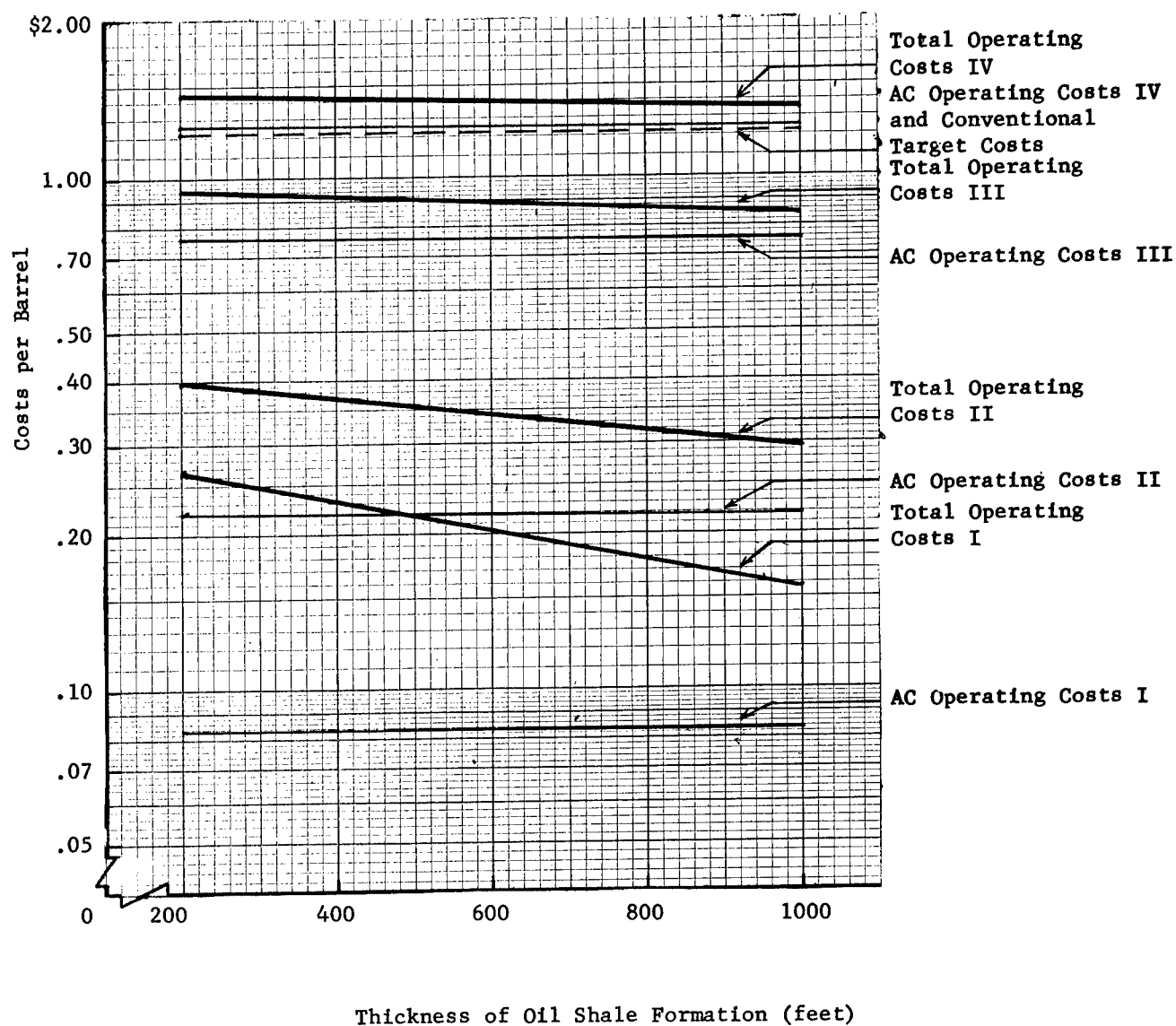
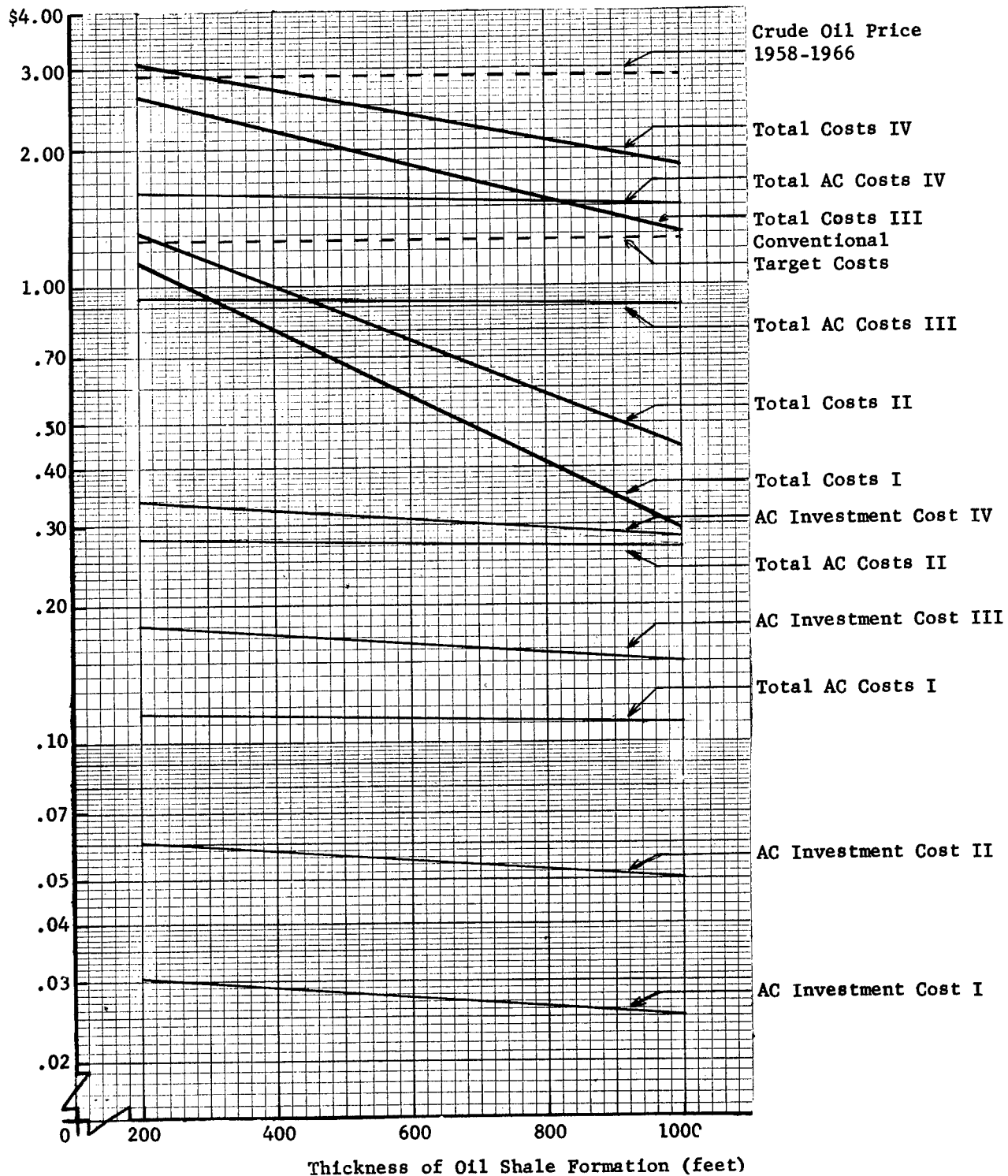


Figure 3.7
Total Costs per Barrel of Oil Shale
As a Function of Air Compressor (=AC) Costs.
(four cases, see text)



other parameters; for example, the 70 per cent recovery rate or lower grades would already exclude this process due to excessive costs if such extreme pressure requirements prove necessary. High pressures may be called for in water-rich formations ("wet" formations) using the in situ combustion method. In addition, the ignition of the rubble causes, in this case, added difficulties. A process avoiding combustion of the material altogether, for example by hot gas injection, might prove to be more efficient in such cases.

In "dry" formations the 50 psig pressure requirement may suffice, especially as air pressure drops across the rubble zone nuclear chimneys have been very low [117].

Beyond the microeconomic significance, the implications for the United States economic resource picture are enormous, as the high grade reserves of the Piceance Basin, the low grade reserves of the Uinta, Green River, Washakie, and Sand Wash Basins are added to the known, economically recoverable reserves and to other oil shale formations of potentially equal significance (black shales of the Mississippian and Devonian formation). All oil shale grades in excess of ten gallons are significantly below the \$2.90 average crude oil price at the well-head though not necessarily above the \$1.25 "target" costs if at least some of the above assumptions (especially air compressor requirements) are within the neighborhood of present predictions and expectations. In order to substitute the above given ranges of expected costs by more detailed and more accurate figures,

very extensive experiments are needed. As it stands now, the in situ recovery of shale oil using nuclear explosives may imply tremendous economies of scale. If the very specific technical assumptions are attained in the future processes yet to be tested by experiments, then this would have major implications for the United States economy; and expectations are such that for the first time a major utilization of these vast resources of the United States is within reach over the next decade.

Appendix I

COST ESTIMATES FOR OIL SHALE EXPERIMENT

Given by CER GEONUCLEAR

(50 KT, 3, 000 feet depth)

PHASE I OF EXPERIMENT

Pre-Shot Program

Site and improvement	640 acres land	\$ 30, 000
Access to site and road improvement		15, 000
Three core wells at \$50, 000		150, 000
Device emplacement well		140, 000
Field and Laboratory analysis of shale core samples, pressure and injectivity tests and down- hole television or photos		60, 000
Safety Considerations		
Seismic (survey instrumenta- tion and documentation)		50, 000
Ground water (identification, documentation, and other geologic studies)		100, 000
Weather program		20, 000
Nuclear device (fielding, firing, security, instrumentation, and documentation)		500, 000

Post-Shot Program

Emplacement hole (re-entry)	\$ 30,000
Well No. 5 (new and deviated holes)	75,000
Well No. 1 (re-entry)	15,000
Well No. 2 (re-entry and deviation)	50,000
Three new wells (6, 7, and 9, including 3 deviated holes)	250,000
Well No. 8	50,000
Field and laboratory analysis of core injection tests, downhole photos or TV	75,000
Safety Considerations	
Seismic	60,000
Rad-Safe (air sampling, plane, remote monitoring)	80,000

Miscellaneous and Logistic Support

Labor and Supervision*	150,000
Communications network, field office utilities, site operation, maintenance, and support	350,000
Contingency (20%)	<u>300,000</u>
TOTAL COSTS OF PHASE I	\$1,830,000

* Note: Direct Labor and Supervision is included in \$150,000 figure.
Consulting time spent by members of the consortium is not included.

PHASE II COSTS FOR IN SITU RETORTING OF CHIMNEY

Gas Turbine Air Compressors

Basis: 40 MMSCFD @ 50 psig
 Total brake horsepower (77% Eff.) -- 5350
 Total cost at \$150 / BHP \$ 802,000

Production Wells 160,000

Basis: Four 8-1/2-inch completions or equivalent at
 2800 feet, whipstocked into the base of R. P.,
 equipped with 2-7/8-inch tubing and 1500 BOPD
 tbg. pump and jack

Temperature Observation Wells 125,000

Basis: Three 5-1/2-inch supplementary air injection/T/C
 wells spaced about 75 feet from the device hole
 and drilled to the bottom of the rubble pile for
 temperature profile measurements.

Surface Equipment 100,000

Basis: Surface storage -- 10,000 bbls.
 Emulsion treating equipment, pipe line
 connection, pumps, and lines.

Total Operating Costs -- Compressors 188,000

Basis: \$28/BHP-hr
 Fuel 10 SCF/BHP-hr at 30 cents/MSCF plug
 maintenance

Treating Costs at 10 cents/bbl oil 80,000

Miscellaneous and Logistical Support 150,000

Labor, Supervision, Testing 150,000

\$1,755,000

Contingencies (20%) 300,000

TOTAL COSTS PHASE II \$2,055,000

PHASE III COSTS FOR IN SITU RETORTING OF FRACTURED ZONE

Air Compressors

Basis: 5 MMSCF/D at 3000 psig
 Total horsepower (80% Eff.) -- 2,600
 Total cost at \$200/BHP \$ 520,000

Injection and/or Production Wells 200,000

Basis: Five 6-inch completions or
 equivalent cored and logged
 to 2800 feet

Temperature Observation Wells 100,000

Basis: Three supplementary air injection/
 thermocouple wells drilled through the
 heated interval for temperature
 measurement

Post-Burn Core Wells 100,000

Basis: Three supplementary wells cored
 through the heated interval
 verify areal sweep

Total Operating Costs - Compressors 75,000

Basis: One year's operation at \$28/BHP-yr
 10 scf/BHP-hr gas cost at 30 cents/MSCF

Miscellaneous and Logistical Support 100,000

Labor, Supervision, Testing 100,000

Thermocouples and Analytical Equipment

Basis: Thermocouples, gas analysis
 equipment, etc. 50,000

Contingencies (20% of costs) \$1,245,000
 225,000

TOTAL COSTS PHASE III \$1,470,000

Appendix II

ASSUMPTIONS FOR CASES II, III, AND IV SHOWING THE EFFECT OF VARYING AIR COMPRESSOR REQUIREMENTS FOR IN SITU SHALE OIL PRODUCTION [242]

1. TECHNICAL DATA

	<u>Case II</u>	<u>Case III</u>	<u>Case IV</u>
Yield in KT	200	200	200
Depth, in feet	3,000	3,000	3,000
Chimney Characteristics			
Lithology factor	325	325	275
Radius, in feet	210	210	178
Height, in feet	1,050	1,090	890
Rubble mass, in tons	7.3×10^6	7.3×10^6	4.5×10^6
Grade of oil shale, gal/ton	25	25	25
Total shale oil content	4.4×10^6	4.4×10^6	2.7×10^6
Recovery factor (in two years)	70%	50%	50%
Air rate in scf/ton	7,100	7,100	7,100
Operating pressures, psig	50	1,000	1,000
Investment, \$/BHP	150	200	200
Operating cost, \$/BHP	28	35	35

2. INVESTMENT COSTS IN \$	Case II		Case III		Case IV	
	Total	per barrel	Total	per barrel	Total	per barrel
Emplacement hole, 15-inch diameter	100,000	.03	100,000	.05	100,000	.08
Device, safety, timing, firing (assumed)	300,000	.09	300,000	.13	300,000	.22
Air injection wells (two)	120,000	.05	120,000	.05	120,000	.09
Production wells (four)	160,000	.05	160,000	.07	160,000	.12
Surface storage, lines, treating equipment	80,000	.03	80,000	.04	80,000	.06
Compressors	180,000	.06	460,000*	.18	460,000*	.34
Subtotal (investment costs)	\$ 940,000	\$.31	\$1,220,000	\$.52	\$1,220,000	\$.91
3. OPERATING COSTS						
Compressors	650,000	.22	1,680,000*	.76	1,680,000*	1.25
Treating Costs	300,000	.10	300,000	.10	135,000	.10
Lifting Costs	150,000	.05	150,000	.05	67,500	.05
Overhead	150,000	.05	150,000	.05	67,500	.05
Subtotal (operating costs)	\$1,250,000	\$.42	\$2,280,000	\$.96	\$1,950,000	\$1.45
TOTAL	\$1,790,000	\$.73	\$3,100,000	\$1.51	\$2,770,000	\$2.36

* Assumes that these air compressors suffice for both chimneys.

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